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

Idaho Power Company

July 2011

FY 2012–2013

FINAL
AVERAGE SYSTEM COST REPORT

FOR

Idaho Power Company

Docket Number: ASC-12-IP-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: **Idaho Power Company (Idaho Power)**
1221 W. Idaho St.
Boise, Idaho 83702
http://www.idahopower.com/default.cfm

Parties to the Filing:

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

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

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

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

Effective Exchange Period: Fiscal 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 Idaho Power'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 ASC Final Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's ASC Draft Reports. If a party failed to do so, the issue is waived for subsequent appeal. *See* Rules of Procedure for BPA's ASC Review Processes, § 3.7.1.3 ("Rules of Procedure").

2 AVERAGE SYSTEM COST SUMMARY

2.1 Idaho Power Company Background

Idaho Power is an investor-owned utility engaged in the generation, transmission, distribution, sale and purchase of electric energy and is subject to both state and federal regulations. The company, based in Boise, Idaho, has an electric generation capacity of more than 3,200 megawatts (MW). The company operates 14 hydroelectric generating plants on the Snake River and its tributaries; two natural gas-fired plants (Bennett Mountain and Danskin); and a share of three jointly owned coal-fired plants (Boardman, Jim Bridger, and Valmy). Generation statistics for 2009 are shown in the table below.

Idaho Power 2009 Electric Generation and Energy				
Type	**Capacity (MW)**	**Percent**	**Energy (MWh)**	**Percent**
Hydro	1,695	52%	8,028,152	44%
Coal	1,118	34%	6,940,808	38%
Natural Gas	436	13%	242,352	1%
Other	16	0%	68,324	0%
Purchases			2,911,842	16%
Misc Adj.			(132,868)	-1%
Total	**3,265**	**100%**	**18,058,610**	**100%**

Idaho Power, 2009 FERC Form 1, April 12, 2010.

Idaho Power provides electric service to over 489,000 customers in Southern Idaho (95% of customer base) and Eastern Oregon. Idaho Power's 24,000-square-mile electric system includes over 4,700 miles of transmission lines and 26,675 miles of distribution lines.

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 Idaho Power on June 1, 2010, including errata filed on June 28, 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	$588,623,919	$579,840,399
Transmission Cost	$120,003,417	$120,385,797
(Less) NLSL Costs	$16,122,868	$20,391,305
Contract System Cost (CSC)	**$692,504,468**	**$679,834,891**
Total Retail Load (MWh)	13,903,800	13,948,280
(Less) NLSL	236,879	281,042
Total Retail Load (Net of NLSL)	13,666,921	13,667,238
Distribution Losses	561,697	563,494
Contract System Load (CSL)	**14,228,618**	**14,230,732**
CY 2009 Base Period ASC (CSC/CSL)	**$48.67/MWh**	**$47.77/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 Idaho Power filed on June 28, 2010 including errata filed on June 26, 2010, and as adjusted by BPA for this Final ASC Report. If no new resources were to come on line, and no changes were to occur with NLSLs, the ASC shown in Table 2.3-1 below would be Idaho Power's ASC for the entire Exchange Period. See Table 6.1 for details of Exchange Period ASC changes relating to new resources and NLSLs.

Several factors may increase or decrease the Exchange Period ASC from the As-Filed date (June 1, 2010) to the Final ASC Report (July 26, 2011), including adjustments made through the ASC Review Process. Among other changes that may affect a utility's 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 Idaho Power's Filing on June 1. For additional details, see Section 3.6 of this report and the "Inputs" tab of the ASC Forecast Model for the utility's (1) As-Filed and (2) BPA-Adjusted models.

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

Date	June 1, 2010 As-Filed	July 26, 2011 Final Report
FY 2012–2013	47.49	45.55

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 June 28, 2010. The Final Report ASC reflects BPA's adjustments to the utility's As-Filed ASC.

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

As-Filed FY 2012–2013 Exchange Period ASC

Resource	Hemmingway	Exergy Wind	N/A	N/A
Expected On-Line Date*	01/01/11	01/01/2011		

Final Report FY 2012–2013 Exchange Period ASC				
Resource	**Hemmingway**	**Exergy Wind**	**N/A**	**N/A**
Expected On-Line Date*	01/01/11	01/01/2011		

*See ASC Summary Table 6.1 for details.

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

As-Filed FY 2012–2013 Exchange Period ASC

Resource	Langley Gulch	N/A	N/A	N/A
Expected On-Line Date*	07/01/2012			

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

*See ASC Summary Table 6.1 for details.

2.5 NLSL Adjustment

A new large single load (NLSL) is any load associated with a new facility, an existing facility or an expansion of an existing facility that was not contracted for or committed to (CF/CT) prior to September 1, 1979, and which will result in an increase in power requirements of ten average megawatts (aMW) or more in any consecutive 12-month period. 16 U.S.C. § 839a(13)(A)-(B).

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

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

For purposes of this Final ASC report, BPA has determined that each of the large loads identified as "Customer Group" below is a NLSL. The cost of resources in an amount sufficient to serve these potential NLSLs has been removed from the Utility's ASC. The Idaho Power had the opportunity to rebut this presumption by providing BPA with information that established either: (1) that the identified load did not exceed 10 aMW in a 12-month period; or (2) the load is fully or partially protected under the "contracted for or committed to" exemption in the Northwest Power Act. Idaho Power submitted data identifying the customer group below as an NLSL and confirmed the customer load of 439,587 MWh. The final ASC report will adjust the utility's ASC to reflect BPA's final NLSL determinations. To protect the confidentiality of the customer, the loads are identified by a pseudonym.

Table 2.5-1: New Large Single Loads Reviewed

As-Filed FY 2012–2013 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
"Customer Group"	236,879

Final Report FY 2012–2013 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
"Customer Group"	439,587

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

As-Filed FY 2012–2013 Exchange Period ASC				
Customer	**"Customer A"**	**"Customer B"**	**N/A**	**N/A**
Expected Start Date	Already in Service	2010		

Final Report FY 2012–2013 Exchange Period ASC				
Customer	**"Customer A"**	**"Customer B"**	**N/A**	**N/A**
*Expected Start Date	Already in Service	2010		

*Customer B's expected date is based on IPUC's May 28, 2010 Power Cost Adjustment rate case documentation. See ASC Summary Table 6.1 for details.

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

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

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

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 Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act" or "Act"), 16 U.S.C. § 839c(c), established the Residential Exchange Program ("REP"). Under the REP, any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at a rate established pursuant to sections 7(b)(l) and 7(b)(3) of the Act. H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and small-farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act grants to BPA's Administrator the authority to determine utility ASCs based on a methodology established in a public consultation proceeding. *See* 16 U.S.C. § 839c(c)(7). In designing this methodology, the Act specifically requires the Administrator to exclude from ASC three categories of costs:

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

Id.

The first ASC Methodology was developed in consultation with regional parties in 1981. *See* 48 Fed. Reg. 46,970 (1983) ("1981 ASCM"). After three years of experience with the 1981 ASCM, BPA revised the ASC Methodology in 1984. *See* 49 Fed. Reg. 39,293 (1984) ("1984 ASCM"). After 23 years of experience under the 1984 ASCM, BPA commenced another consultation proceeding in 2007 to revise the 1984 ASCM. The goal of the consultation process was to update the ASC Methodology to reflect the significant changes that had occurred in the electric utility industry since 1984, modify the review procedures, and develop an administratively feasible ASC methodology that would be technically sound and comport with the Northwest Power Act. The end result of this consultation was the 2008 ASCM. In June of 2008, BPA filed the 2008 ASCM with the Federal Energy Regulatory Commission

("Commission") for the Commission's "review and approval." 16 U.S.C. § 839c(c)(7). On September 15, 2009, the Commission granted final approval to BPA's 2008 ASCM. No party contested the Commission's final ruling.

Consistent with BPA's ASC review procedures, BPA conducts a prescribed review of ASC Filings to ensure compliance with the 2008 ASCM. *See* Rules of Procedure at § 1. For more information regarding the 2008 ASCM, please refer to the Commission's final ruling and 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 ASC Filing by contacting BPA. Parties wishing to formally intervene in a utility's ASC proceeding could file an intervention by the date identified in BPA's ASC Review Process Schedule. Intervenors were afforded multiple opportunities to request data, submit comments, and raise issues with the utilities' ASCs. The filing utilities, in turn, were afforded opportunities to respond to requests for data, raise and respond to issues, and answer any questions relative to the Filings.

The Review Processes for FY 200 are complete. This Final ASC Report reflects BPA's review of the utility's ASC Filing and addresses, preliminarily, the issues and questions raised by the utility, intervenors and BPA Staff in the utility's ASC Review Process. The final ASC determinations and supporting justifications are published in the Final ASC Report for each participating utility and can be viewed at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

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

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 support data are as follows:

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

3.3.1 Schedule 1 – Plant Investment/Rate Base

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

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

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

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

3.3.2 Schedule 1A – Cash Working Capital

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

Cash working capital is a ratemaking convention that is not included in the FERC Uniform System of Accounts, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a utility, BPA allows one-eighth of the functionalized costs of total production expenses, transmission expenses and administrative and general expenses, less purchased power, fuel costs, and public purpose charges into rate base. *See* 18 C.F.R. § 301, End. f.

3.3.3 Schedule 2 – Capital Structure and Rate of Return

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

The 2008 ASCM requires IOUs to use the weighted cost of capital (WCC) from their most recent state commission rate order. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula described in Endnote b of the 2008 ASCM. *See* 18 C.F.R. § 301, End. b.

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

3.3.4 Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production, transmission, and distribution of electricity. Each expense item is functionalized as outlined in Table 1 of the 2008 ASCM. Also included in Schedule 3 are additional expenses associated with customer accounts, sales, administrative and general expense, conservation program expense, and depreciation and amortization expense associated with Electric Plant-in-Service. The sum of the items in Schedule 3 reflects the Total Operating Expenses for the utility.

3.3.5 Schedule 3A – Taxes

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

Federal income taxes are included in ASC and are calculated, as applicable, in Schedule 2, Capital Structure and Rate of Return.

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

3.3.6 Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity for others (wheeling). The revenues in this schedule are deducted from the total costs of each utility.

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

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Capital Structure and Rate of Return, Expenses, Taxes, and Other Included Items. The schedule also identifies the Contract System Cost and Contract System Load, as defined below, and calculates the utility's Base Period ASC ($/MWh).

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

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

3.3.8 Purchased Power and Sales for Resale

Purchased Power is an Account in Schedule 3—Expenses, and includes all power purchases the utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B—Other Included Items, and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Please refer to the FERC Form 1, pages 310-311, for Sales for Resale, and pages 326-327, for Purchased Power, for identification of the classification codes.

3.3.9 Load Forecast

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

The total retail and residential and small-farm load forecasts are adjusted for distribution losses and NLSLs when appropriate. The resulting load forecasts are the Contract System Load forecast and Exchange Load forecast, respectively.

3.3.10 Distribution Loss Calculation

Each utility is required to provide 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 reporting.

3.3.13 Major Resource Additions – Individual and Grouped

The 2008 ASCM allows a utility's ASC to adjust during the Exchange Period to reflect the addition or loss of a major new resource, subject to the materiality threshold of 2.5 percent. New resources are defined as any new production or new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments. *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 midpoint of the Exchange Period; or (2) for new resources that are expected to be on line during the Exchange Period, BPA calculates the new resource cost as if the resource came on line at the midpoint of the Exchange Period.

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

3.3.14 New Large Single Loads

This tab calculates the cost of resources in an amount sufficient to serve an NLSL, which BPA must exclude from the utility's ASC pursuant to Northwest Power Act section 5(c)(7). An NLSL is any load associated with a new facility, an existing facility, or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and which will result in an increase in power requirements of ten average megawatts (aMW) or more in any consecutive 12-month period. 16 U.S.C. § 839a(13)(A)–(B). By law, BPA must exclude from a utility's ASC the load associated with an NLSL and an amount of resource costs sufficient to serve such NLSL. *See* 16 U.S.C. § 839c(c)(7)(A). To determine the amount of resource costs to exclude from a utility's ASC, BPA follows the methodology described in Endnote d of the 2008 ASCM. *See* 18 C.F.R. § 301, End. d.

3.3.15 Tiered Rates

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

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

3.3.16 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 the new resources also changes.

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

In the FY 2009 and FY 2010–2011 ASC Review Processes, significant changes occurred between the Draft ASC Reports and Final ASC Reports that affected the materiality test for several groups of resources. As a result of these changes, several groupings of new resources no longer met the 2.5 percent materiality threshold. However, because these changes occurred after the close of the comment period on the Draft ASC Reports, BPA 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 proposed to change the timing of the materiality determination. During customer workshops held on October 6, 2009, February 25, 2010, and April 21, 2010, BPA explained its concern with the current timing of the materiality determination and the grouping/regrouping of new resources. After considering the public comments presented in the workshops, and the comments supplied by parties in response to BPA's letter dated March 1, 2010, BPA proposed to change the timing of the materiality decision from the Final ASC Report to the Draft ASC Report. BPA proposed this change in order to provide parties with one additional opportunity to comment on the ordering or stacking of new resource additions or reductions. BPA views this approach as the most advantageous means of determining materiality because, first, it does not place the burden on BPA 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 Staff has 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.

3.4 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- 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.

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

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

3.5 ASC Forecast

Once the Base Period ASC is calculated, BPA uses the ASC Forecast Model to escalate forward the Base Period ASC to the mid-point 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.

3.5.1 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 mid-point 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.

3.5.2 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).

3.5.3 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.

3.5.4 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 Idaho Power in BPA's August 24, 2010, Issue List and November 19, 2010, Draft Report. Idaho Power 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 as resolved.

4.1.1 Schedule 1: Plant Investment/Rate Base

4.1.1.1 Account 253 – Other Deferred Credits

Issue:

Whether Idaho Power correctly functionalized the line items in Account 253, Other Deferred Credits.

Parties' Positions:

In its initial Appendix 1, Idaho Power functionalized all line items in Account 253, Other Deferred Credits, to Distribution/Other.

BPA's Position:

BPA agrees with Idaho Power's As-Filed functionalization of line items reported in Account 253.

Evaluation of Positions:

During review of the individual line items contained within Account 253, BPA Staff questioned the functionalization and the documentation provided in Idaho Power's As-Filed Appendix 1. Idaho Power later submitted its Response to BPA's Issue List provided detailed documentation for the functionalization of Account 253.

Idaho Power, in its BPA Issue List Response, stated:

> Idaho Power met with representatives from BPA on Tuesday, August 31, 2010, following the ASC workshop to discuss this matter. At that time, Idaho Power provided exhibits from its Idaho Power-E-08-10 General Rate Case which demonstrated that Accounts 253 and 254 are excluded for State Commission ratemaking purposes. Please refer to Pages 1-2 of Attachment A which are Rate Base computation pages from Idaho Power's Revenue Requirement Model and which itemize Additions and Deletions to Ratebase. The Account 253 documentation is attached as Attachment D. Idaho Power did not make changes to the items in Account 253 in its Appendix 1, for purposes of this Issue List item.

Idaho Power's Response to BPA Issue List, September 2, 2010, at 3.

After meeting with Idaho Power representatives and reviewing the documentation provided in Idaho Power's response to BPA's Issue List, BPA accepts Idaho Power's treatment of Account 253.

Decision:

BPA will use Idaho Power's As-Filed functionalization of Account 253.

Table 4.1.1-1: Account 253

	Total	Production	Transmission	Dist/Other
As-Filed	19,363,271	0	0	19,363,271
Adjusted	19,363,271	0	0	19,363,271

4.1.1.2 Account 186 – Miscellaneous Deferred Debits

Issue:

Whether Idaho Power correctly functionalized the costs of Other Workers Compensation reported in Account 186, Miscellaneous Deferred Debits.

Parties' Positions:

In its initial Appendix 1, Idaho Power included the costs of Other Workers Compensation in Account 186 and functionalized to Distribution/Other.

BPA's Position:

The costs of Other Workers Compensation recorded in Account 186 should be functionalized to Distribution/Other.

Evaluation of Positions:

In its Appendix 1, Idaho Power included "Other Workers Compensation" in Miscellaneous Deferred Debits and functionalized it to Distribution/Other. Idaho Power also noted that the account is excluded from rate base for ratemaking purposes.

Idaho Power in their BPA Issue List Response to Idaho Power stated:

> Idaho Power met with representatives from BPA on Tuesday, August 31, 2010, following the ASC workshop to discuss this matter. At that time, Idaho Power provided exhibits from its IPC-E-08-10 General Rate Case outlining which items from FERC Account 186 are included in the rate base component of the filing. Pages 1-2 of Attachment A include Rate Base computation pages from Idaho Power's Revenue Requirement Model. Pages 3-6 are the related work papers also filed in that case. Pages 7-9 include the updated work papers (actual, year-ending 2009).Those exhibits are attached as Attachment A. The Account 186 documentation tab is attached as Attachment C. Idaho Power did not make changes to the items in Account 186 in its Appendix 1, for purposes of this Issue List item.

Idaho Power's Response to BPA Issue List, September 2, 2010, at 2.

After meeting with Idaho Power representatives and reviewing the documentation provided in Idaho Power's response to BPA's Issue List, BPA accepts Idaho Power's treatment of Other Workers Compensation.

Decision:

BPA will functionalize Other Workers Compensation in Account 186 to Distribution/Other.

Table 4.1.1-2: Other Workers Compensation

	Total	Production	Transmission	Dist/Other
As-Filed	1,328,786	0	0	1,328,786
Adjusted	1,328,786	0	0	1,328,786

4.1.2 Schedule 4: Average System Cost

4.1.2.1 Exchange Load

Issue:

Whether Idaho Power submitted the correct 2009 total retail sales in Schedule 4 and in the Load Forecast tabs of the Appendix 1.

Parties' Positions:

In its initial Appendix 1, Idaho Power submitted its 2009 Total Retail Load in Schedule 4 and the Load Forecast tab on a fiscal-year basis.

BPA's Position:

The 2009 Total Retail Load for both Schedule 4 and the Load Forecast tabs should be prepared on a calendar-year basis.

Evaluation of Positions:

The CY 2009 load recorded in the load forecast tab and Schedule 4 of the Appendix 1 did not match the load data recorded in the FERC Form 1, page 401a.

In Data Response BPA-IP-FY12-15, Idaho Power revised the load data from fiscal to calendar. *See* Idaho Power's Response to BPA Data Request BPA-PA-FY12-15, July 12, 2010, at 1. The Load Forecast tab requires fiscal-year load information, which is what Idaho Power provided when it completed the Appendix 1 and the resulting link to the Schedule 4 tab. *Id.* The FERC Form 1 data requires calendar-year load information. *Id.*

BPA and Idaho Power agree that the Total Retail Load reported in Schedule 4 of the Appendix 1 should contain the value as found in the FERC Form 1 (page 401a).

Decision:

BPA will correct Total Retail Sales in both Schedule 4 and the Load Forecast tabs MWhs for 2009 to match the calendar year 2009 FERC Form 1 amount.

Table 4.1.2-1: Total Retail Load

	CY 2009 Total Retail Load
As-Filed	13,903,800
Adjusted	13,948,280

4.1.3 New Resources – Individual

4.1.3.1 New Resource Materiality Test

Issue:

Whether BPA's new resource materiality test is calculated correctly and whether the results are being displayed correctly in the Individual and Grouped tabs in the Appendix 1.

Parties' Positions:

Idaho Power requests that BPA verify the materiality for new resources is being calculated correctly and displayed in both Individual and Grouped New Resources tabs in the Appendix 1.

BPA's Position:

BPA Staff corrected the materiality calculation and the percentages displayed in the Individual and Group New Resources tabs in an email from BPA to filing parties on May 25, 2010.

Evaluation of Positions:

On August 24, 2010, Idaho Power posted to its docket an Issue List to BPA which requested that BPA ensure that the calculation for materiality was correct and that the number shown was being displayed on the Individual and Group tabs consistently. *See* Idaho Power's Issue List to BPA, at 1.

BPA Staff responded on September 3, 2010, and stated that both the materiality calculation and the percentages shown on both the Individual and Group New Resources tabs are in good working order and functioning correctly. *See* BPA response to Idaho Power Issue List, at 1. BPA also noted in its response that there was no material impact to ASCs. *Id.*

Decision:

BPA views this issue as resolved since the issue has been previously addressed in a May 25, 2010 email from BPA to filing utilities which contained the corrected Appendix 1. BPA has also verified that the calculations are functioning correctly.

4.2 Identification and Analysis of Unresolved Issues

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

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

4.2.1.1 Account 182.3 – Other Regulatory Assets

Issue:

Whether the regulatory assets capitalization of FAS 87 pension expense and costs associated with corporate headquarters growth planning reported in Account 182.3 should be functionalized to Labor or Distribution/Other.

Parties' Positions:

Idaho Power functionalized the regulatory assets capitalization of FAS 87 pension expense and costs associated with corporate headquarters growth planning to Labor.

BPA's Position:

Regulatory assets capitalization of FAS 87 pension expense and costs associated with corporate headquarters growth planning reported in Account 182.3 should be functionalized to Distribution/Other.

Evaluation of Positions:

In its initial ASC Filing, Idaho Power functionalized capitalization of FAS 87 pension expense and costs associated with corporate headquarters growth planning by the Labor ratio.

In Data Response BPA-IP-FY12-01, Idaho Power did not provide BPA sufficient information to justify the functionalization of capitalization of FAS 87 pension expense and costs associated with corporate headquarters growth planning by the Labor ratio. *See* Idaho Power's July 9, 2010 response to BPA's Data Request BPA-IP-FY12-01, at 1.

In a conference call between BPA Staff and Idaho Power Staff on July 22, 2010, Idaho Power accountants clarified that regulatory assets recorded in Account 182.3 may receive a return on the unamortized balance (recorded in Schedule 3, Expense) but that none of the line items recorded in this regulatory account receive an additional Rate of Return (ROR) to be recovered in retail rates.

Based on the information from the conference call, BPA Staff agreed with Idaho Power that the correct functionalization treatment for these items is Distribution/Other. It was BPA's understanding at the time of the above-mentioned conference call that Idaho Power agreed that the individual line items within Account 182.3 should be functionalized to Distribution/Other.

However, in its response to BPA's Issue List, Idaho Power argued that the two individual line items — capitalization of FAS 87 pension expense and costs associated with corporate headquarters growth planning — should be functionalized to Labor. *See* Idaho Power's Response to BPA Issue List, September 2, 2010, Attachment B, at 1.

The 2008 ASCM ROD is clear that "[u]nder no conditions would regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates." 2008 ASCM at 149. Neither capitalization of FAS 87 pension expense nor costs associated with corporate headquarters growth planning are included in Idaho Power's rate base used to establish retail rates. The return allowed by Idaho Power's state commissions is built into the amortization of the regulatory assets.

<u>Decision:</u>

BPA will functionalize the line items capitalization of FAS 87 pension expense and costs associated with corporate headquarters growth planning to Distribution/Other.

Table 4.2.1-1a: Account 182.3 - Regulatory Assets, Capitalization of FAS 87 Pension Expense

	Total	Production	Transmission	Dist/Other
As-Filed	572,286	206,072	86,772	279,442
Adjusted	572,286	0	0	572,286

Table 4.2.1-1b: Account 182.3 - Regulatory Assets, costs associated with corporate headquarters growth planning

	Total	Production	Transmission	Dist/Other
As-Filed	7,395	2,663	1,121	3,611
Adjusted	7,395	0	0	7,395

4.2.2 Schedule 1A: Cash Working Capital

No direct adjustments.

4.2.3 Schedule 2: Capital Structure and Rate of Return

No direct adjustments.

4.2.4 Schedule: Expenses

No direct adjustments.

4.2.5 Schedule 3A: Taxes

No direct adjustments.

4.2.6 Schedule 3B: Other Included Items

4.2.6.1 Account 421 – Miscellaneous

Issue:

Whether Idaho Power correctly functionalized all the line items in Miscellaneous Non-Operating Income.

Parties' Positions:

Idaho Power functionalized all line items included in Account 421 to Distribution/Other.

BPA's Position:

The line items reported in Account 421 should all be functionalized according to Table 4.2.6.1 below:

Table 4.2.6.1: BPA's Position of Account 421

A	B	E
	Line Item	BPA Staff Recommendation
421000	MSC NONOP INC	Production
421006	MSC NONOP INC-PCA-FCA-IDAHO	Production
421008	MSC NONOP INC-EXCESS PWR-OR	Production
421050	MSC NONOP-EX DEF COMP-INT&DIV	Labor
421051	MSC NONOP-EX DEF COMP-RLZD GNS	Labor
421052	MSC NONOP-EX DEF COMP-UNRLZ GN	Labor

Evaluation of Positions:

In its Appendix 1 and data Response to BPA Data Request BPA-IP-FY12-06, Idaho Power stated that the items listed in column B above are "1) Carrying charges, not allowed in the Company's Rate Base, and 2) Investments made on behalf of the executives' savings plan assets; including assets, interest, gains, unrealized gains, etc." *See* Idaho Power's Response to BPA's Data Request BPA-PA-FY12-06, July 9, 2010, at 1. Idaho Power claims these accounts are excluded for ratemaking purposes. *Id.*

However, in its previous FY 2010-2011 ASC Filing, Idaho Power used a Direct Analysis to functionalize Account 421 as shown in column D of Table 4.2.6.2 below:

Table 4.2.6.2: BPA's Position of Account 421

A	B	C	D	E
	Line Item	CY 2009 Filing	CY 2007 Idaho Power Filing	BPA Staff Recommendation
421000	MSC NONOP INC	Other	PTD	Production
421006	MSC NONOP INC-PCA-FCA-IDAHO	Other	Production	Production
421008	MSC NONOP INC-EXCESS PWR-OR	Other	Production	Production
421050	MSC NONOP-EX DEF COMP-INT&DIV	Other	PTD	Labor
421051	MSC NONOP-EX DEF COMP-RLZD GNS	Other	PTD	Labor
421052	MSC NONOP-EX DEF COMP-UNRLZ GN	Other	PTD	Labor

The 2008 ASCM states that once a utility uses a specific functionalization method for an Account, the utility may not change the functionalization for that Account without prior written approval from BPA. *See* 18 C.F.R. § 301.7 (c)(1). Idaho Power did not request authorization from BPA to functionalize Account 421 to the Default method, Distribution/Other.

The 2008 ASCM also states that the utility must submit with its Appendix 1 any and all work papers, documents, or other materials that demonstrate that the functionalization under its Direct Analysis assigns costs based upon the actual and/or intended functional use of those items. *See* 18 CFR § 301.7 (c)(2). Failure to submit such documentation could result in the entire Account being functionalized to Distribution/Other, or Production, or Transmission, as appropriate. *Id.*

Because Idaho Power did not request prior approval to use the default method to functionalize Account 421 and because it did not supply sufficient documentation to support functionalization of Account 421 to Distribution/Other by its Direct Analysis, BPA could not functionalize all of the items in Account 421 to Distribution/Other. However, BPA believes there is sufficient data contained within Idaho Power's ASC Filing to make a reasonable estimate of the correct functionalization for the listed items. Therefore, based on the available information, BPA functionalized the items in Idaho Power's ASC is as follows:

Table 4.2.6.3: BPA's Position of Account 421

A	B	E
	Line Item	**BPA Staff Recommendation**
421000	MSC NONOP INC	Production
421006	MSC NONOP INC-PCA-FCA-IDAHO	Production
421008	MSC NONOP INC-EXCESS PWR-OR	Production
421050	MSC NONOP-EX DEF COMP-INT&DIV	Labor
421051	MSC NONOP-EX DEF COMP-RLZD GNS	Labor
421052	MSC NONOP-EX DEF COMP-UNRLZ GN	Labor

Decision:

BPA will functionalize the line items in Account 421 according to column E of the Table 4.2.6.3, BPA's Position of Account 421, above.

Table 4.2.6-1: Miscellaneous Nonoperating Income Account 421

	Total	Production	Transmission	Dist/Other
As-Filed	7,178,192	0	0	7,178,192
Adjusted	7,178,192	6,534,710	152,469	491,014

4.2.7 Schedule 4: Average System Cost

4.2.7.1 Distribution Losses

No direct adjustments. Idaho Power Company submitted a distribution loss factor calculation of 4.04 percent.

4.2.7.2 Contract System Cost

CY 2009 Contract System Cost ($)

As-Filed		Adjusted	
Production	588,623,919	Production	579,840,399
Transmission	120,003,417	Transmission	120,385,797
Less NLSL	16,122,868	Less NLSL	20,391,305
Total	692,504,468	Total	679,834,891

4.2.7.3 Contract System Load

CY 2009 Contract System Load (MWh)

	Total
As-Filed	14,228,618 MWh
Adjusted	14,230,732 MWh

4.2.7.4 Average System Cost

CY 2009 Average System Cost ($/MWh)

	Total
As-Filed	48.67
Adjusted	47.77

4.2.8 New Large Single Loads

4.2.8.1 Cost of Serving NLSLs

Issue: Cost of Serving NLSLs (#1)

Whether BPA should adopt the proposed Endnote d(3) Interpretation.

Parties' Positions:

Idaho Power argues that BPA's proposed interpretation is inconsistent with both the Northwest Power Act and the 2008 ASCM.

BPA's Position:

The proposed interpretation of Endnote d(3) is consistent with the Northwest Power Act and the 2008 ASCM and should be used to determine the cost of resources necessary to serve NLSL.

Evaluation of Positions:

To understand the issues presented by Idaho Power's comments, it is necessary to explain the factual context behind BPA's decision to revise certain components of the NLSL Tab that implements Endnote d(3) of the 2008 ASCM. Provided below is a summary of the facts that led BPA to propose the Endnote d(3) Interpretation. This discussion may also be found on pages 1-4 in BPA's Endnote d(3) Interpretation, which is attached to this report as Attachment A.

Background:

Idaho Power argues that BPA's proposed interpretation is inconsistent with both the Northwest Power Act and the 2008 ASCM. *See* Idaho Power's September 2, 2010 response to BPA Issue List, at 7. In addition, Idaho Power claims that BPA's revised interpretation of Endnote d(3) inappropriately allocates the costs of general plant, plant materials and supplies, general plant depreciation, and A&G to resources in the NLSL calculation, resulting in the loss of additional REP benefits to Idaho Power's consumers. *See* Idaho Power Issue List, at 1. The IPUC filed comments supporting Idaho Power's opposition. *See* IPUC's Response to Idaho Power's Issue List, September 2, 2010, at 1.

In October of 2008, BPA commenced two concurrent ASC Review Processes to establish utility ASCs for FY 2009 and FY 2010-2011. These proceedings were the first ASC reviews BPA conducted under the terms of the 2008 ASCM. During the course of these proceedings, a number of NLSLs were reported in the ASC filings. Because none of these NLSLs were served with "dedicated resources," nor did any of the utilities with NLSLs purchase power from BPA at the NR rate, BPA used subpart (3) of Endnote d to calculate the cost of resources sufficient to serve these NLSLs. The operative language from Endnote d(3) that guided BPA's calculation is as follows:

> . . . the costs of the excess load will be determined by multiplying the kilowatt-hours not served under paragraphs (d)(1) and (d)(2) above, by the cost (annual fixed plus variable cost, including an appropriate portion of general plant, administrative and general expense and other items not directly assignable) per kilowatt-hour of all resources and long term power purchases (five years or more in duration), as allowed in the regulatory Jurisdiction to establish retail rates during the Exchange Period . . .

To implement this language, BPA developed the NLSL resource cost spreadsheet ("NLSL Tab"). The NLSL Tab allowed parties to input resource-specific data for all cost categories except (1) General Plant and (2) Administrative and General Expense ("A&G"). For these two accounts, the NLSL Tab required exchanging utilities to use a ratio based on installed generating capacity. Although the NLSL Tab met the requirements of Endnote d(3), the spreadsheet and BPA's proposed allocation factors did not receive much scrutiny during the ASC Review Processes.

Following the publication of the FY 2009 and FY 2010-2011 Final ASC Reports, BPA performed a detailed review of the models and spreadsheets used in the ASC calculation. As part of this review, BPA revisited the NLSL Tab. This review revealed two problems with the existing NLSL Tab spreadsheet. First, BPA discovered that two cost categories, General Plant Depreciation Expense and Federal and State Employee Taxes, were inadvertently left out of the NLSL Tab. These cost categories should have been included in the NLSL calculation.

Second, BPA found the method it had been using to determine the cost of resources for NLSL purposes was different than the method BPA had been using to determine the cost of resources for ASC purposes. For example, in the NLSL Tab, the cost item Plant Materials and Supplies was determined through a direct analysis performed by the utility. In the Appendix 1, however, Plant Materials and Supplies are functionalized using the PTD[3] ratio. *See* 18 C.F.R. Pt. 301, Tbl. 1. A&G costs were similarly misaligned. In the NLSL Tab, all A&G costs were allocated using the ratio of post-September 1, 1979 generating capacity to total generating capacity. In the Appendix 1 and ASC Forecast Model, however, A&G costs were broken out into fifteen separate FERC accounts, each of which was assigned a ratio by the 2008 ASCM. *Id.* Of the fifteen A&G accounts in the Appendix 1 and ASC Forecast Model, six accounts are allocated using the Labor Ratio, six are assigned to Distribution, two are allocated by the PTDG ratio and one by the General Plant ratio. *Id.* A similar difference existed for General Plant, where the NLSL Tab used the previously described plant capacity ratio for all General Plant costs, while the Appendix 1 and ASC Forecast Models broke out General Plant into twelve FERC accounts and used three different ratios to assign the individual General Plant accounts. *Id.*

After discovering the inconsistent functionalization treatment, BPA reviewed the 2008 ASCM to determine whether there was any basis for calculating NLSL resource costs differently than resource costs in ASC. Finding none, BPA proposed to revise the NLSL Tab through a revised interpretation of Endnote d(3).

Endnote d(3) requires BPA to include in the NLSL resource calculation "an appropriate portion of general plant, administrative and general expense and other items not directly assignable. . ." *See* 18 C.F.R. § 301, Appendix 1, 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. To fill this "gap" in the 2008 ASCM, BPA proposed 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 specific changes BPA proposed to make through its interpretation were as follows:

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

BPA submitted its proposed Endnote d(3) Interpretation for public comment on two occasions. *Id.* at 5. Idaho Power individually and the IOUs collectively, filed comments on BPA's

[3] Production, Transmission, and Distribution.

Endnote d(3) Interpretation. *Id.* at 5-12. BPA responded to these comments in the Endnote d(3) Interpretation. *Id.*

<u>Idaho Power's Comments and BPA's Response:</u>

During the ASC Review Processes, BPA allowed parties additional opportunities to submit comments on BPA's proposed Endnote d(3) Interpretation. Idaho Power submitted comments opposing the Endnote d(3) Interpretation. *See* Idaho Power's Response to BPA's Issue List, September 2, 2010, at 7; *see* Idaho Power Issue List, at 1. The IPUC filed comments supporting Idaho Power's opposition. *See* IPUC's Response to Idaho Power's Issue List, September 3, 2010, at 1.

Idaho Power claims that the proposed interpretation is erroneous for two reasons. *See* Idaho Power's Response to BPA Issue List, September 2, 2010, at 7. First, Idaho Power argues BPA's treatment of costs of peaking plants is inappropriate. *Id.* Idaho Power claims it has included costs of additional resources in amounts more than sufficient to serve any new large single load customer in its FY 2012–2013 ASC Filing. *Id.* Idaho Power further asserts that large load customers (including NLSL customers) by nature are the Company's least expensive loads to serve. *Id.*

BPA disagrees with Idaho Power's argument. Idaho Power claims that BPA's decision to include peaking plants is inappropriate, but does not cite the proper authority to support its assertion. As BPA has noted in every filing it has produced on this topic, Endnote d(3) *requires* BPA to calculate the NLSL calculation based on "all resources and long term power purchases. . ." 18 C.F.R. § 301, End. d(3). Thus, the 2008 ASCM does not permit BPA to "pick and choose" which resources to include in the calculation. If Idaho Power believed this language was in error, then it should have filed a challenge to the 2008 ASCM. It did not, and therefore, BPA cannot depart from the unambiguous requirements of the 2008 ASCM to accede to Idaho Power's request.

Idaho Power next claims that large industrial loads (including NLSL customers) are "by nature" the company's least expensive loads to serve. Response of Idaho Power to BPA Issue List, at 7. Thus, Idaho Power argues that peaking units should not be included in the resource calculation because NLSLs tend to be "relatively flat." *Id.* If they are included, Idaho Power claims that the costs should be proportioned in an amount sufficient to match the NLSL's contribution to a system peak above base load only—not the peak in its entirety. *Id.* Idaho Power then incorporates by reference the comments it raised before the Commission opposing Endnote d(3). *Id.*

Idaho Power's argument must be rejected for several reasons. First, this comment is clearly outside of the scope of BPA's proposed Endnote d(3) Interpretation. Nowhere in the interpretation does BPA even hint that it is reconsidering which resources to include in its calculation of Endnote d(3). As Idaho Power notes, Idaho Power raised its objection to the text of Endnote d(3) before the Commission. Despite Idaho Power's objection, the Commission approved the ASCM, *including Endnote d(3)*. *See* Sales of Electric Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology, 74 Fed. Reg. 47,052-01

(2009). BPA cannot reconsider the language the Commission has already approved. Idaho Power's comment seeks to challenge Endnote d(3) rather than BPA's *interpretation* of the existing language. Consequently, Idaho Power's argument is outside of the scope of this proceeding and must be rejected.

Second, BPA has already responded to Idaho Power's claim that Endnote d(3) does not properly take into account the characteristics of the load in the Endnote d(3) Interpretation and in filings before the Commission. *See* Endnote d(3) Interpretation at 8-10; BPA Motion for Leave to Respond to Idaho Power's Arguments that were Improperly Raised in Reply Comments, Docket Nos. EF08-2011-000, RM08-20-000, dated January 12, 2009. To the extent that Idaho Power's claim is relevant to the issues in the Endnote d(3) Interpretation, which they are not, BPA incorporates by reference its previous responses. *Id*.

Third, Idaho Power's concern that large loads are, in fact, less expensive to serve than other loads is irrelevant for purposes of calculating the exclusion of NLSL costs. Congress designed the Act to intentionally discourage NLSLs from relocating to the Pacific Northwest:

> [u]nder this bill, rates for increased loads resulting from any new commercial and industrial activity ('New Large Single Loads', section 3(12)) are excluded from the Federal base resource rate. Thus, any Utility seeking additional power to serve such a load would be charged a rate equivalent to the new resource cost. This new resource cost should be the same or higher than the cost to utilities in other regions to serve such load. This provision should help to narrow, rather than expand, the Northwest's advantage in attracting new industry through lower cost electricity.

H.R. Rep. No. 96-976, Pt. I, 96th Cong. 2d Sess. 43-44 (1979).

Following Idaho Power's logic, BPA should only be excluding the low-cost resources from the ASC calculation when excluding NLSL costs, which would have the perverse effect of increasing Idaho Power's ASC. This argument was soundly rejected in the 2008 ASCM ROD. *See* 2008 ASCM ROD at 92-93.

Also, Idaho Power's "cost of serving" argument is based either on a mischaracterization or misreading of the NLSL provision of the Northwest Power Act, which specifically requires the Administrator to exclude from ASC the cost of additional resources *in an amount sufficient to serve* any new large single load of the Utility. *See* 16 U.S.C. § 839c(c)(7)(A) (emphasis added). Neither the Northwest Power Act nor the 2008 ASCM makes any reference whatsoever to the "cost of serving NLSLs." That mischaracterization of the Northwest Power Act is by itself enough to invalidate most of Idaho Power's arguments concerning BPA's revised Endnote d(3) Interpretation. The Northwest Power Act and the 1981, 1984 and 2008 ASCMs all refer to the cost of additional resources *in an amount sufficient to serve* any new large single load of the Utility. *See* 1981 ASCM Footnote 15(b); 1984 ASCM Footnote (f); 2008 ASCM Endnote d.

Finally, the existing text of Endnote d provides a solution to Idaho Power's alleged inequity. Endnote d(1) permits BPA to exclude the costs of dedicated resources from ASC.

18 C.F.R. § 301, End. d(1). If Idaho Power believes that its NLSL is being served only by low-cost resources, it should dedicate those resources to its NLSL and use the provisions of Endnote d(1) to calculate the cost of resources to exclude from ASC. Idaho Power has never explained why this provision does not solve its concerns.

Idaho Power claims that BPA proposed interpretation “over-assign[s] and double-count[s] resource costs and expenses.” Idaho Power’s Response to BPA Issue List, September 2, 2010, at 7. To support these statements, Idaho Power points to the 2008 ASCM, where BPA presented a fully allocated cost of $34 to $40 per MWh for the Boardman Plant depending upon the capacity factor of the plant. *Id.; see also* 2008 ASCM, at 89. Idaho Power claims that under BPA’s new calculation methodology proposed in the Endnote d(3) Interpretation, this figure becomes $44.85 per MWh, or 21% greater than the average of BPA; estimate from its 2008 ASCM ROD. *Id.* Idaho Power asserts that a 21% increase should be considered a significant change and departure from the results of a direct allocation calculation, which more fairly and reasonably captures the intention of the 2008 ASCM and the Act. *Id.* Idaho Power claims that its calculation of the cost submitted in its Appendix 1 with the June 1, 2010 Filing is within the bounds of the BPA estimated range of fully allocated costs for the plant from the 2008 ASCM ROD. *Id.*

Idaho Power’s reliance on this example is misplaced. The section cited by Idaho Power relates to a section in the 2008 ASCM where BPA is explaining its rationale for *moving away* from using base load resources alone in the NLSL calculation. BPA proposed this change because relying on base load resources only in the NLSL calculation could result in an ASC *increasing* in the event BPA were to remove the base load resource costs from ASC. The full context of the language cited by Idaho Power is provided below:

> In the ASCM consultation process, BPA staff discussed its concern that, for many utilities, the resource cost determination prescribed in Endnote d could result in a cost of resources below a Utility’s ASC. This is because many of the resources used in the calculations were large, central station, coal-fired resources that were installed in the early 1980s. Because some of these resources are near the end of their depreciable lives, the return component is low and fuel and variable O&M are also low. Analysis prepared by BPA staff and discussed during the consultation process indicated that the fully allocated cost of Colstrip Units 3 and 4 was about $30-34/MWh and Boardman was about $34-40/MWh depending on the capacity factor of the plant. Colstrip Units 3 and 4 and Boardman are both baseload resources built in the early 1980s and would be a part of the NLSL resource cost determination for many of the IOUs. This contrasts with current wholesale market prices in the $60-80/MWh range and the fully allocated cost of gas-fired combined cycle combustion turbines (CCCTs) in the $60-65/MWh range.
>
> For utilities that own a large quantity of baseload resources built in the early 1980s, it will be many years before the quantity and cost of new baseload resources, such as CCCTs, result in an NLSL resource cost determination that is higher than the utilities’ respective ASCs. If the NLSL resource cost

> determination is below a Utility's ASC, it will result in an increase in that Utility's ASC. *BPA believes that increasing a Utility's ASC as a result of excluding the costs of serving NLSLs is inconsistent with the intent of the NLSL provisions of the Northwest Power Act. When BPA serves a preference customer, any NLSL service is priced at BPA's NR rate, which generally reflects current incremental resource costs.*

ASCM ROD, at 89 (emphasis added).

As the above text makes clear, BPA's analysis in this section was merely illustrative of a problem that existed under the previous NLSL calculation in the 1984 ASC Methodology. By removing cheap base load resources from ASC on account of an NLSL, a utility's ASC could potentially benefit because the only remaining resources would be higher-cost resources. BPA decided that such an outcome was illogical and therefore determined that

> the NLSL resource cost determination must reflect the current types of resources acquired by exchanging utilities. BPA will include <u>all</u> post-September 1, 1979, generating resources in the determination of the cost of resources used to serve NLSLs to better reflect the diversity of generating resources exchanging utilities use to meet the requirements of meeting their customers' energy requirements. Review of any current integrated resource plan or similar document prepared by a regional Utility would clearly show that relying on baseload generating resources for NLSL resource cost determinations is out of touch with modern generating resource portfolios.

ASCM ROD, at 89-90.

In its comment, however, Idaho Power has ignored the illustrative nature of these figures and purported them as binding ASC determinations on the appropriate cost to be excluded from ASC for the Boardman plant. Idaho Power's Response to BPA Issue List, September 2, 2010, at 7. Idaho Power claims that when comparing BPA's illustrative figures generated two years ago in the ASCM ROD with the present-day figures that were generated in a six-month ASC Review Process, the net difference is 21%. *Id.* Idaho Power asserts that a 21% increase should be considered a significant change and departure from the results of a direct allocation calculation, which more fairly and reasonably captures the intention of the ASC Methodology and the Act. *Id.* This comparison, however, is inapposite. The 2008 ASCM could not be clearer that this figure was not expected nor intended to be a final determination of *actual* resource costs. The ASCM ROD specifically states that

> Analysis prepared by BPA staff and discussed during the consultation process indicated that the fully allocated cost of Colstrip Units 3 and 4 *was about* \$30-34/MWh and Boardman *was about* \$34–40/MWh *depending on the capacity* factor of the plant.

ASCM ROD, at 89.

As these statements make clear, the figures referenced in the 2008 ASCM ROD were high-level estimates of resource costs and were not intended as definitive findings of the costs of the Boardman resource. These numbers were not constructed with the same precision or analysis that BPA Staff uses when developing resource cost calculation in the ASC Review Processes. Moreover, the figures developed in the 2008 ASCM ROD were based on data that BPA had at the time, which was from 2006. These figures cannot be compared to the specific resource information that BPA Staff reviewed in this proceeding, which relies on resource data developed in CY 2009, and escalates it to the midpoint of the Exchange Period. Consequently, comparing the 2008 ASCM ROD's illustrative figures from two years ago to the *actual* costs BPA has determined following six months of review in an ASC Review Process is simply illogical.

Also, Idaho Power's arguments inappropriately compare Endnote d resource cost calculations from different years. Endnote d resource cost calculations are annual costs which vary from year to year because of changes in such components as return on equity, coal or natural gas prices, and the actual generation of the resource. For example, in 2006 the Boardman coal plant, of which Idaho Power is a co-owner, experience an extended outage due to problems with the generator rotor. The fully allocated cost of Idaho's share of the Boardman plant in 2006 was $55/MWh based on BPA's 2009 Final ASC Report for Idaho Power. However, the fully allocated cost of Idaho's share of the Boardman plant in 2007 dropped to $35/MWh. The dramatic drop in the cost of the Boardman between 2006 and 2007 was almost entirely due to the 40% capacity factor[4] of Boardman in 2006 as a result of the outage. In 2007, after repairs were complete and Boardman returned to normal operations, the capacity factor was 78%. The fully allocated cost of resources will vary from year to year for a variety of reasons, completely independent of the calculation methodology.

Finally, the 2008 ASCM ROD does not address the central issue which BPA sought to resolve through its Endnote d(3) Interpretation. As noted before, the question being resolved through the Endnote d(3) Interpretation is the proper treatment in the NLSL calculation of Plant Materials & Supplies, General Plant, General Plant Depreciation Expense, Administrative and General Expense (A&G), Property Taxes, and Federal and State Employee Taxes. The 2008 ASCM ROD focused on the more general question of what resources to include in the NLSL calculation, and therefore did not specify the method for allocating the aforementioned costs in the NLSL calculation. *See* 2008 ASCM ROD, at 88-93. The only guidance in the 2008 ASCM ROD on the treatment of these costs was an instruction to "[c]alculate the fully allocated costs of the 'Base Period' post-1979 resources (fully allocated costs include return, depreciation expense, O&M, Fuel, allocated A&G, and Property taxes)." *Id.*, at 93. The method for "calculating" the fully allocated costs, however, was not addressed. Thus, a "gap" was left in both the 2008 ASCM ROD and the 2008 ASCM that BPA is properly filling here with the adoption of the Endnote d(3) Interpretation.

Idaho Power next contends that in its prior year's ASC filings its proposed cost for the Boardman facility was accepted in BPA's Final ASC Reports. Idaho Power's Response to BPA Issue List,

[4] The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period. U.S. Energy Information Agency Glossary.

September 2, 2010, at 7. Idaho Power is incorrect. While BPA may have *allowed* a certain NLSL cost method in the previous ASC filings, neither the FY 2009 Final ASC Reports nor the FY 2010-2011 Final ASC Reports determined what the proper treatment of Plant Materials & Supplies, General Plant, General Plant Depreciation Expense, Administrative and General Expense (A&G), Property Taxes, Federal and State Employee Taxes would be in the NLSL calculation. As noted in the "Background" section of this issue, BPA did not discover the inconsistency within the NLSL Tab until after the Final ASC Reports were issued. Thus, BPA only allowed this treatment because it did not know it was inconsistent with other provisions of the 2008 ASCM.

The absence of any substantive discussion on this issue in the prior ASC Reports undermines Idaho Power's claim that BPA's previous allowance of this treatment is precedential. Indeed, both the FY 2009 Final ASC Report and the FY 2010-2011 Final ASC Report clearly state that BPA allowance of a particular calculation without comment is not to be construed as approval of the proffered treatment:

> BPA's ASC determination is limited to specific findings on those issues identified for comment, with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASCM.

FY 2009 Final ASC Report, Idaho Power, at 11; FY 2010-2011 Final ASC Report, Idaho Power, at 11.

Because BPA has not previously evaluated the treatment of Plant Materials & Supplies, General Plant, General Plant Depreciation Expense, Administrative and General Expense (A&G), Property Taxes, Federal and State Employee Taxes in the NLSL calculation, the fact that BPA *allowed* a different treatment in previous ASC Reports is irrelevant.

Idaho Power asserts that under BPA's new Endnote d(3) Interpretation, there is a "significant increase to the cost." Idaho Power's Response to BPA Issue List, September 2, 2010, at 7. Idaho Power claims that when compared to the FERC Form 1, BPA's comparable "Expenses per Net KWH" is approximately $10 greater (36%) per MWh than the 0.0269 per kWh as calculated by the FERC Form 1 (page 402, line 35), not including the additional 13% increase to "Return on Capital" that BPA has also incorrectly assumed by allocating excessive costs to the Boardman plant.

Idaho Power's assertion that BPA's Endnote d(3) interpretation results in a significant increase to plant costs relates to BPA's treatment of allocated costs and was raised by Idaho Power as a separate issue. *See* Idaho Power's Issue List, August 24, 2010, at 1. BPA addresses this separate issue in Section 4.2.8.3 of this report.

Idaho Power next argues that the Endnote d(3) interpretation results in "double-counting expenses" for two non-owner-operated plants. Idaho Power's Response to BPA Issue List, September 3, 2010, at 7. Idaho Power claims that the new NLSL tab in general, allocates peaking expenses to "relatively non-peaking load." *Id.* Idaho Power asserts that the result of the calculation does not conform to either the Company's own approved retail rates for a NLSL customer or the costs as calculated in the FERC Form 1. *Id.* Idaho Power concludes that the effect of all of the above is an assignment of costs far greater than the "amount sufficient to serve any new large single load of the utility." *Id.*

BPA is unsure as to what Idaho Power is attempting to argue in this comment. First, Idaho Power's comment does not explain how BPA is "double-counting" costs in the NLSL tab. Thus, BPA cannot formulate a response to this conclusory statement. Second, Idaho Power's observation that the NLSL Tab "allocates peaking expense to relatively non-peaking load[s]" makes no sense. *Id.* BPA does not know what a "relatively non-peaking load" is or why the characteristic of the load matters for purposes of determining the cost of serving an NLSL. BPA can only assume that Idaho Power is attempting to surreptitiously assert in another form its argument that the costs of peaking resources be excluded from the NLSL calculation. If that is Idaho Power's intent, then BPA has already thoroughly addressed this issue above.

The next two observations in Idaho Power's comment are equally vague. Idaho Power first observes that the results of the Endnote d(3) Interpretation do not "conform to . . . the Company's own approved retail rates for a NLSL customer." *Id.* However, Idaho Power does not explain *why* the results of BPA's NLSL calculation *must* conform to the retail rates of Idaho Power's NLSL. Indeed, the 2008 ASCM specifically contemplates that BPA's ASC determinations will, in many instances, *not* conform to the retail rate treatment afforded by the state commissions. This outcome is not odd or illogical, but a natural result of BPA's decision to move away from a jurisdictional-based approach to ASC determinations. As noted in the 2008 ASCM ROD:

> Using the jurisdictional cost approach as the data source for the ASC calculations has proven to be inefficient, cumbersome, and extremely contentious. BPA therefore is proposing to not use a jurisdictional costing approach for the revised ASCM. In its place, BPA is proposing to use a data source that is uniform and that facilitates ease of administration for all parties.

2008 ASCM ROD, at 24.

Idaho Power's second observation is even more cryptic. Idaho Power claims that BPA's proposed Endnote d(3) Interpretation does not conform to ". . . the costs as calculated in the FERC Form 1." Idaho Power's Response to BPA Issue List, September 2, 2010, at 7. Factually, this comment is incorrect because the only information BPA used to calculate the cost of serving Idaho Power's NLSL was from Idaho Power's Appendix 1, which is based on Idaho Power's FERC Form 1. Without further details as to how BPA's proposed Endnote d(3) Interpretation fails to conform to Idaho Power' FERC Form 1, BPA cannot formulate a response to this comment.

In its final salvo, Idaho Power asserts that BPA has not followed all the language in the 2008 ASCM in the Endnote d(3) Interpretation. *Id.* Idaho Power claims that, under the

2008 ASCM, NLSL costs are limited to the amount "allowed in the regulatory jurisdiction to establish retail rates during the Exchange Period." *Id.* Idaho Power claims that the retail rate for the NLSL is "substantially less" than the total rate applied to the load using either of BPA's NLSL methodologies. *Id.* Idaho Power concludes that the current NLSL methodology in use in the Appendix I does not conform to the ROD determination that the cost of the NLSL is the amount "allowed in the regulatory jurisdiction to establish retail rates during the Exchange Period." *Id.*

It is unclear from this comment whether Idaho Power seeks to challenge the Endnote d(3) Interpretation or BPA's implementation of Endnote d(3) generically. Either way, Idaho Power's view of the ASCM is misguided. The provision Idaho Power relies on states as follows:

> To the extent that NLSLs are not served by dedicated resources plus the Utility's purchases at the NR rate, the costs of the excess load will be determined by multiplying the kilowatt-hours not served under paragraphs (d)(1) and (d)(2) above, by the cost (annual fixed plus variable cost, including an appropriate portion of general plant, administrative and general expense and other items not directly assignable) per kilowatt-hour of all resources and long term power purchases (five years or more in duration), as allowed in the regulatory Jurisdiction to establish retail rates during the Exchange Period . . .

18 C.F.R. § 301, End. d(3).

The operative language Idaho Power relies on is the final phrase "as allowed in the regulatory Jurisdiction to establish retail rates during the Exchange Period . . ." Idaho Power claims this phrase limits the NLSL calculation to only the cost of resources used to set the retail rates of the *utility's* NLSL. Idaho Power's Response to BPA Issue List, September 2, 2010, at 7. This reading of Endnote d(3), however, is faulty. The text cited by Idaho Power does not say that the only resource costs used in the NLSL calculation are those costs used to set the "retail rates" of the NLSL. Parsing the language into its component parts, the language is intended to read as follows:

> the costs of the excess load will be determined by multiplying the kilowatt-hours not served under paragraphs (d)(1) and (d)(2) above . . . by the cost . . . per kilowatt hour of all resources and long term power purchases . . . , as allowed in the regulatory Jurisdiction to establish retail rates during the Exchange Period. . .

Read properly, the text says that the cost included in the NLSL calculation is the cost of *all resources* that are allowed into retail rates. The "retail rates" referenced in this section are not those applicable only to the NLSL, but the retail rates applicable to *all* of the utility's customers. If the intent of Endnote d(3) was to limit the cost of resources to only those used to serve the NLSL, then the text would have mentioned the NLSL in the latter half of the sentence. It does not, so the more natural reading of the sentence leads to the conclusion that the reference to "retail rates" is to retail rates of all customers of the utility, not just the retail rates of the NLSL. Consequently, if the resource cost is in retail rates, then the resource cost is properly in the NLSL calculation. This result makes sense because resource costs that are not in retail rates would not be resource costs allowed in ASC. Section 5(c)(7)(B) specifically excludes from ASC 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 . . ." 16 U.S.C. § 839c(c)(7)(B). Resources that are dedicated to out-of-region loads would be resources that would not be "allowed in the regulatory Jurisdiction to establish retail rates" and therefore would not be resources included in the NLSL calculation. BPA's method of calculating NLSL costs would exclude these out-of-region resources, and therefore the current method of calculating NLSL costs is consistent with the ASCM.

Idaho Power claims that the current methodology BPA uses to determine the cost of serving an NLSL is improper because it does not limit the costs in the NLSL calculation to only those included in "retail rates." Idaho Power's Response to BPA Issue List, September 2, 2010, at 7. However, Idaho Power does not explain in its comment how BPA's proposed Endnote d(3) Interpretation violates this phrase. Idaho Power has not identified any costs included in the NLSL calculation that are not allowed in retail rates. Thus, BPA's Endnote d(3) Interpretation properly implements the terms of Endnote d(3) and should be adopted.

Decision:

The proposed Endnote d(3) Interpretation is consistent with the 2008 ASCM and should be used to determine the cost of serving a utility's NLSLs. BPA will continue to use Endnote d(3) in calculating Idaho Power's cost of serving NLSLs.

Issue: Cost of Serving NLSLs (#2)

Whether BPA has adequately addressed Idaho Power's concerns over the inclusion of peaking resources in the NLSL calculation.

Parties' Positions:

Idaho Power argues that BPA has not adequately addressed its concerns over BPA's inclusion of peaking resources in the NLSL calculation.

BPA's Position:

The 2008 ASCM, Endnote d provides the prescribed method for calculating resource costs sufficient to serve an NLSL. Endnote d(3) requires BPA to include in the calculation of resources sufficient to serve an NLSL *all* resources of the utility, including peaking resources. Excluding peaking resources from the NLSL is not permitted by Endnote d(3) of the 2008 ASCM.

Evaluation of Positions:

Idaho Power argues that BPA has not adequately addressed its concerns over BPA's inclusion of peaking resources in the NLSL calculation. Idaho Power Issue List, at 1. The Idaho Public Utilities Commission supports Idaho Power's comment and adds that it is unlikely that a peaking unit will ever be used to serve an NLSL. *See* IPUC's Response to BPA Issue List, September 3, 2010, at 1.

Idaho Power claims it has received no satisfactory resolution of the outstanding issue from the last ASC review process that has been carried forward into this process. Idaho Power Issue List, at 1. Specifically, Idaho Power asserts that BPA is continuing to include Idaho Power's peaking resources in the NLSL Base calculation. *Id.* Idaho Power claims that that peaking resources were not built in response to delivery energy to relatively flat NLSLs, and therefore, should be excluded from the NLSL calculation. *Id.*

Idaho Power's concern with the inclusion of certain peaking resources in the NLSL resource calculation is a challenge to the 2008 ASCM, not BPA's staff implementation of the 2008 ASCM. The ASCM could not be clearer on this point. Endnote d(3) of the 2008 ASCM expressly requires that NLSL costs be calculated using "all resources and long term power purchases[.]" 18 C.F.R. § 301, End. d(3). In the 2008 ASCM ROD, BPA also clearly stated that it intended to include *all of the utility's* resources in the NLSL calculation:

> BPA will include all post-September 1, 1979, generating resources in the determination of the cost of resources used to serve NLSLs to better reflect the diversity of generating resources exchanging utilities use to meet the requirements of meeting their customers' energy requirements.

ASCM ROD, at 89. BPA repeated this point in the "decision" portion of the ASCM ROD:

> *The ASCM will determine the cost of serving NLSLs using the fully allocated cost of all escalated Base Period post-September 1, 1979, resources and major resource additions and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs. Because wind resources comprise an increasingly larger share of exchanging utilities' resource portfolios, and many utilities may be acquiring more wind resources than carbon fueled resources, the ASCM is eliminating the requirement that a resource must be a baseload resource to be included in the NLSL resource cost determination.*

ASCM ROD, at 93.

The only resources exempted from inclusion in the NLSL calculation are those expressly identified in Endnote d(3) itself. They include the following:

(a) purchases at the NR rate;
(b) purchases at the PF Exchange rate, pursuant to section 5(c) of the Northwest Power Act;
(c) resources sold to Bonneville, pursuant to section 6(c)(1) of the Northwest Power Act;
(d) dedicated resources specified in endnote d(1) of this Methodology;
(e) resources and purchases committed to the Utility's load as of September 1, 1979, under a power requirements contract or that would have been so committed had the Utility entered into such a contract; and

(f) experimental or demonstration units or purchases therefrom.

18 C.F.R. § 301, End. d(3). Peaking resources are not one of the identified resources excluded from the NLSL calculation.

As the foregoing makes clear, BPA is simply following the terms of the 2008 ASCM when it includes all of Idaho Power's resources, including the peaking resources Idaho Power contests, in the NLSL resource calculation. Idaho Power has not identified any provision of the ASCM or the Northwest Power Act which permits Idaho Power to exclude certain peaking units from the NLSL calculation. Moreover, as BPA noted in its Endnote d(3) Interpretation, the 2008 ASCM allows Idaho Power to dedicate resources to serve an NLSL. If Idaho Power dedicates a resource to serve its NLSL, then the costs of only that resource will be excluded from its ASC. Idaho Power has not adequately explained to BPA why this option, which is expressly permitted under the 2008 ASCM, does not solve Idaho Power's issue.

Idaho Power claims that it has not received a "satisfactory resolution" of this issue. BPA, however cannot, give a "satisfactory resolution" to Idaho Power on this issue because the ASCM does not permit the resolution Idaho Power requests. If Idaho Power does not accept BPA's explanation of Endnote d(3), it is not for lack of trying by BPA. Counting this report, BPA has responded to Idaho Power's concerns on Endnote d(3) no fewer than four times. Idaho Power originally raised this issue in the ASC Review Process for FY 2010-2011. At that time, Idaho Power filed comments with the Federal Energy Regulatory Commission objecting to BPA's proposed implementation of the then-pending 2008 ASCM. BPA responded to Idaho Power's late-filed objections with its own comment. *See* BPA Motion for Leave to Respond to Idaho Power's Arguments that were Improperly Raised in Reply Comments, Docket Nos. EF08-2011-000, RM08-20-000, dated January 12, 2009. The Commission ultimately rejected Idaho Power's challenges and approved the 2008 ASCM as filed by BPA. *See* Sales of Electric Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology, 74 Fed. Reg. 47,052-01 (2009).

Idaho Power then raised this issue again during the review of its FY 2010-2011 ASC. BPA responded to Idaho Power's comment in the Final ASC Report for FY 2010-2011. *See FY 2*010-2011 Final ASC Report, Idaho Power Company, at 57-60 (July 2009). Finally, when BPA submitted for public comment its proposed Interpretation of Endnote d(3), which looked only to make minor adjustments to the allocation of Plant Materials and Supplies, A&G, General Plant, General Plant Depreciation Expense, Property Taxes, and Federal and State Employee Taxes as used in Endnote d(3), Idaho Power again raised all of its concerns with Endnote d(3). BPA responded to these concerns in its Endnote d(3) Interpretation. *See* Attachment A.

In short, BPA has adequately responded to Idaho Power's concerns.

<u>Decision:</u>

BPA has adequately addressed Idaho Power's concerns regarding the inclusion of peaking resources in the NLSL calculation.

4.2.8.2 NLSL Data

Issue:

Whether Idaho Power provided all requested NLSL data for the FY 2012–2013 ASC Filing.

Parties' Positions:

Idaho Power withheld detailed data and information concerning Idaho Power's large load customers (10 aMW or higher) in its initial response to Data Request BPA-IP-FY12-08 due to confidentiality concerns.

BPA's Position:

BPA has received detailed load information from Idaho Power, and BPA Staff has handed the information off to BPA's NLSL Staff for possible NLSL and CF/CT determinations of Idaho Power's large load customers.

Evaluation of Positions:

Since the drafting of the Issue List to Idaho Power, Idaho Power and BPA have come to an agreement on confidentiality issues pertaining to Idaho Power's large load customer data. Idaho Power has provided sufficient documentation for all large loads to BPA NLSL Staff and BPA was able to make its initial determination of Idaho Power's NLSL load for Idaho Power's Draft Report. Since publishing the Draft Reports, BPA has reviewed NLSL data and made final NLSL and CF/CT determinations for Idaho Power's large load customers. For purposes of Idaho Power's Final ASC Report, BPA will use the NLSL load amount as stated in Issue 4.2.8.4 of this report

Decision:

BPA has received detailed load information from Idaho Power, BPA's NLSL Staff have made final NLSL and CF/CT determinations of Idaho Power's large load customers.

4.2.8.3 NLSL Base Calculation: Share of Overhead Costs

Issue:

Whether the share of assigned overhead costs is being calculated correctly, given the ratios used to calculate the cost of serving an NLSL.

Parties' Positions:

Idaho Power believes that the share of assigned cost is being incorrectly calculated when calculating the cost of serving an NLSL.

BPA's Position:

BPA calculates the cost of serving an NLSL according to Endnote d(3) of the 2008 ASCM.

Evaluation of Positions:

In its Issue List, Idaho Power argues that BPA has improperly calculated the overhead costs associated with the cost of serving an NLSL. *See* Idaho Power's Issue List FY12, Idaho Power, August 24, 2010, at 1. Idaho Power references a supporting document, Comments_FY12_Idaho Power, at 3, which it supplied with its initial ASC Filing. In this document, Idaho Power argues that since it is not the owner/operator of the Valmy or Boardman power plants, the overhead costs should not be included in the NLSL calculation. Instead, the amount applied to the multiplication of the allocation ratio should be the number found in the FERC Form 1 that applies to the production related expenses. *Id.* Idaho Power notes that this method would result in a much lower allocation of production expenses for the calculation of NLSL costs. The IPUC has also responded to Idaho Power's Issues List to BPA and stated that they agree with Idaho Power's technical arguments pertaining to the proportional ownership overhead costs allocators. *See* IPUC's Comments on Idaho Power's August 24, 2010 Issue List FY12, Idaho Power, at 1.

BPA, on September 3, 2010, replied to Idaho Power's Issue List, stating:

> The intent of the 2008 ASCM is to include all allowable production and transmission costs and revenues in the determination of the utility's ASC. These costs are a direct input from Idaho Power's FERC Form 1 and include the investment/capital costs (Schedule 1) of the Valmy and Boardman power plants. Schedule 3, Expenses, identifies all (allowable) expenses necessary to operate these plants.

BPA Response to Issue List FY12 Idaho Power, September 3, 2010, at 2.

BPA believes that Endnote d(3) should be interpreted such that the same level of overhead resource costs is used both in the calculation of a utility's ASC and in determining the cost of serving an NLSL. *Id.* Several reasons support this treatment.

First, the revised implementation mitigates the differences between the NLSL resource cost calculation and the ASC calculation. *See* Endnote d(3) Interpretation, at 3-4. The previous NLSL calculation used allocation factors and methods different from the methods BPA used when calculating a utility's ASC. *Id.* This resulted in conflicting allocation treatments for cost categories that were the same in both the ASC calculation and the NLSL calculation. *Id.* For example, Plant Materials and Supplies are line items in both the NLSL resource cost calculation and the Appendix 1. *Id.* However, these costs were allocated under a direct analysis under the NLSL calculation but allocated using the PTD functionalization ratio under the Appendix 1. *Id.* Using the same functionalization codes in both the NLSL calculation and the Appendix 1 avoids these inconsistencies, and ensures that the costs removed from ASC as a result of an NLSL adjustment are determined in the same manner as the costs included in ASC. *Id.*

Second, the revised implementation will be less burdensome to implement for BPA and the exchanging utility. *Id.*, at 4. For BPA, having consistent functionalization codes means the NLSL Tab can be interconnected with the utility's Appendix 1, reducing the burden on BPA Staff of calculating completely separate allocation factors. *Id.* For utilities, the new implementation method will also reduce the administrative burden of filling out the NLSL Tab. *Id.* The previous NLSL Tab required utilities to manually input data into the Plant Materials and Supplies and Property Taxes cost categories for each resource. *Id.* To obtain these values, the utility had to determine the portion of Plant Materials and Supplies and Property Taxes to assign to each of its resources. *Id.* BPA, in turn, had to review the utility's values. *Id.* The revised implementation, which adopts the default functionalizations from the 2008 ASCM, removes this burdensome process.

Third, the revised implementation is also more consistent with the 2008 ASCM's general policy of limiting direct analysis. *Id.* The 2008 ASCM provides exchanging utilities with limited opportunities to perform direct analysis on cost categories. *Id.* Indeed, the 2008 ASCM specifically prohibits direct analysis on an account unless "Table 1 states specifically that a Utility may perform a direct analysis . . ." 18 C.F.R. § 301.7(a). This general limitation on performing direct analysis, however, was not being followed under the previous version of the NLSL Tab. As noted above, the NLSL Tab allowed exchanging utilities to perform direct analysis on the cost categories of Plant and Materials and Property Taxes. Table 1 of the 2008 ASCM, however, requires that these cost categories be functionalized with the PTD and PTDG ratios. BPA's revised implementation corrects this inconsistency by changing the functionalization method for Plant and Materials and Property Taxes to the functionalization requirements in Table 1 of the 2008 ASCM.

In short, BPA believes that having consistent calculations between the allocation of overhead and related items in the NLSL calculation and the ASC calculation is both sensible and reasonable. The plant costs recorded in Idaho Power's FERC Form 1 and used in the ASC determination should be the same costs used in the NLSL cost allocation. *Id.* BPA believes that the calculation of allocated overhead costs is within the prescribed treatment as outlined in Endnote d(3) of the 2008 ASCM.

Idaho Power next argues that BPA is allocating an inappropriate amount of overhead costs, total general plant, plant materials and supplies, general plant deprecation, and A&G to Idaho Power's NLSL because Idaho Power is not the primary owner/operator of the Valmy and Boardman power plants. *Id.* Idaho Power states that for Valmy and Boardman it receives bills for overhead type expenses. *Id.* Idaho Power asserts that it employs a total of only four employees who do in fact charge some of their time directly to fuel expenses for Valmy and Boardman, which allocate directly through FERC Account 501. *Id.* The remaining 327 employees who work in power supply at Idaho Power are directly assigned to the operation, maintenance, relicensing and other requirements of Idaho Power's hydro fleet, and therefore are not includable in the allocated overheads costs for either Valmy or Boardman. *Id.* Idaho Power is concerned that the ratios used to allocate general plant, materials and supplies, taxes, and deprecation are all based upon investment rather than Idaho Power's actual 2009 FERC Form 1 amounts. *Id.*

Idaho Power's objection is misguided. In effect, Idaho Power argues that BPA is allocating a higher share of plant costs to the cost of serving NLSLs for Valmy and Boardman than is actually being spent by Idaho Power. *See* Idaho Power's Comments to BPA, June 1, 2010, at 3. However, if this is the case, then BPA is also allocating a higher share of plant costs to Contract System Cost than is actually being spent by Idaho Power. What Idaho Power fails to realize is that BPA uses the same ratio method to allocate costs for NLSLs as it does to allocate costs for Contract System Costs included in ASC. In effect, then, Idaho Power is asking BPA to include the higher fully allocated costs of Valmy and Boardman for purposes of calculating ASC, but then include only the lower "actual" cost of these resources when calculating the cost to serve NLSLs. Idaho Power cannot have it both ways. If BPA includes the lower costs of Valmy and Boardman in the calculation to serve NLSLs, than for consistency purposes, BPA would also have to adjust Idaho Power's Contract System Cost to reflect the "lower" actual costs of the Valmy and Boardman power plants. Idaho Power does not appear to advocate for this comparable reduction in its ASC, and BPA believes it is unwise to begin to adjust costs in this manner. As noted above, making all of these precise calculations creates a huge administrative burden on BPA and Idaho Power. BPA does not believe undertaking such a task is either reasonable or necessary if another viable alternative is available. BPA believes using the pre-existing ratios identified in the 2008 ASCM for the same cost items is one such alternative. Rather than creating disconnected and inconsistent treatment of similar cost categories, as advocated by Idaho Power, BPA finds that the 2008 ASCM permits BPA to adopt consistent functionalization treatment between the cost items included in the NLSL calculation and the ASC calculation.

Decision:

BPA will calculate the allocated overhead costs of resources used to serve NLSLs using the treatment as outlined in Endnote d(3) of the 2008 ASCM.

4.2.8.4 NLSL Load

Issue:

Whether BPA has assumed an accurate MWh potential NLSL load amount to use for purposes of the ASC Final Report.

Parties' Positions:

Idaho Power believes that its potential NLSL load is 236,879 MWh.

BPA's Position:

Idaho Power's Final Report NLSL load is 439,587 MWh.

Evaluation of Positions:

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

NLSL determinations are not made in the ASC Review Process. Instead, they are identified and made through a separate process conducted by BPA's NLSL Staff tasked specifically with this responsibility. Although NLSLs are determined in another forum, BPA Staff must establish in the ASC Review Process Draft and Final ASC Reports where the cost of serving any potential NLSLs pursuant to the requirements in Endnote d(1)-(3) of the 2008 ASCM is removed. Parties to the ASC Review Processes must also be allowed an opportunity to review and comment on BPA Staff's calculation. For a detailed discussion of BPA's position on potential NLSLs, please see Section 5.1.1 and 5.1.2 of the generic issues.

For the draft ASC reports, BPA assumed an MWh load for potential NLSLs. For the final report, the load was be determined by BPA's NLSL Staff to be 439,587 MWh. BPA will use the final agency determination to exclude the cost of serving any NLSL.

<u>Decision:</u>

For purposes of establishing the cost of serving an NLSL in the Final Report, BPA will use the MWh load of 439,587.

Table 4.2.8-1: New Large Single Loads Reviewed

As-Filed FY 2012–2013 Exchange Period ASC	
NLSL	**Load**
"Customer Group"	236,879

Final Report FY 2012–2013 Exchange Period ASC	
NLSL	**Load**
"Customer Group"	439,587

4.2.9 New Resource Additions

4.2.9.1 Individual Plant Depreciation: Langley Gulch

<u>Issue:</u>

Whether Idaho Power included the necessary plant depreciation data in the New Resource tab for the Langley Gulch new resource project.

Parties' Positions:

In its Appendix 1, Idaho Power failed to enter the plant depreciation amount for the Langley Gulch resource in the New Resources – Individual tab.

BPA's Position:

There should be a plant depreciation amount for Langley Gulch in the New Resources – Individual tab.

Evaluation of Positions:

Depreciation expenses were not included in Idaho Power's ASC Filing for Langley Gulch. In response to a BPA Data Request, Idaho Power stated that depreciation expense can be calculated by multiplying Accounts 350-359 ($31,509,262) by a composite depreciation rate for Accounts 350-359 of 2.07%, which equals $652,242 of depreciation expense per year for Transmission (cell F90). *See* Idaho Power's Response to BPA-IP-FY12-12 and BPA Issue List, September 3, 2010, at 8. And, by multiplying Accounts 340-346 ($395,857,477) by a composite depreciation rate, based on a 35-year plant life, for Accounts 340-346 of 2.86%, which equals $11,321,524 depreciation expense per year for Production (cell F57). *Id.*

BPA agrees with Idaho Power's treatment of the Langley Gulch plant depreciation.

Following the FY 2012-2013 ASC Draft Report comment period and prior to the publishing of Idaho's Final Report, BPA found that a mathematical error had been made when entering the Langley Gulch's transmission and production plant deprecation costs. Instead of entering the depreciation amount for transmission of $652,242 as calculated by multiplying $31,509,262 by the composite depreciation rate of 2.07 percent BPA Staff instead entered the full $31,509,262 in the depreciation for production instead of separately calculating and entering deprecation amounts in both production and transmission. BPA corrected the mathematical error as shown in table 4.2.9-1 and allocated the correct deprecation amounts to both production and transmission.

Decision:

BPA will adjust the plant depreciation amount in the New Resources – Individual tab.

Table 4.2.9-1**: Langley Gulch – Depreciation Amount**

	Depreciation (production)	Depreciation (transmission)
As-Filed	0	0
Draft Report	31,509,262	0
Final Report	11,321,524	652,242

4.2.9.2 Individual Plant Depreciation: Hemmingway

Issue:

Whether Idaho Power included all the necessary plant depreciation data in the New Resource tab for the Hemmingway new resource project.

Parties' Positions:

In its Appendix 1, Idaho Power failed to enter the plant depreciation amount for the Hemmingway new resource in the New Resources – Individual tab.

BPA's Position:

There should be a plant depreciation amount for Hemmingway in the New Resources – Individual tab.

Evaluation of Positions:

Depreciation expenses were not included in Idaho Power's ASC Filing for Hemmingway. In Data Response BPA-IP-FY12-13, Idaho Power responded: "Depreciation expenses were not included in Idaho Power's original filing. Depreciation expenses will be available after closing of Idaho Power's books for June 2010." *See* Idaho Power's Response to BPA Issue List, September 3, 2010, at 8. Idaho Power also noted that depreciation expense can be calculated by multiplying Accounts 350-359 ($58,264,966) by a composite depreciation rate of 2.07%, which equals $1,206,085,00. *Id.*

BPA agrees with Idaho Power's treatment of the Hemmingway transmission plant depreciation.

Following the FY 2012-2013 ASC Draft Report comment period and prior to the publishing of Idaho's Final Report, BPA found that a mathematical error had been made when entering the Hemmingway transmission plant deprecation cost. Instead of entering the depreciation amount of $1,206,085 as calculated by multiplying $58,264,966 by the composite depreciation rate of 2.07 percent BPA Staff entered the full $58,264,966 amount without multiplying by the composite depreciation rate. BPA corrected the mathematical error as shown in table 4.2.9-2.

Decision:

BPA will adjust the plant depreciation amount in the New Resources – Individual tab.

Table 4.2.9-2: Hemmingway – Depreciation Amount

	Depreciation
As-Filed	0
Draft Report	58,264,966
Final Report	1,206,085

4.2.9.3 Treatment of Exergy Wind Resource

<u>Issue:</u>

Whether the Exergy Wind resource should be included as a new resource in Idaho Power's ASC.

<u>Parties' Position:</u>

Idaho Power presents the Exergy Wind resource as a single new resource that complies with the requirements of the 2008 ASCM.

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

The Exergy Wind resource is an aggregation of individual wind contracts. BPA has had insufficient time to fully develop its proposed treatment of aggregated or disaggregated PURPA resources.

<u>Evaluation of Positions:</u>

As noted in Generic Issue 5.4, BPA determined in this ASC Report to not opine at this time on whether the particular aggregation or disaggregation of PURPA resources for state utility purposes should affect the treatment of new resources under the 2008 ASCM. BPA's decision in this regard was influenced by the fact that the parties' comments did not pertain to any particular new resources being considered in these ASC Review Processes. *See* Generic Issue, 5.4.

Following the issuance of BPA's Draft Report, and two weeks before this final Report was scheduled to be published, BPA discovered through communications with Idaho Power that one of Idaho Power's new resource additions, Exergy Wind, was comprised of multiple individual wind contracts that had been aggregated and presented in Idaho Power's ASC Filing as a single resource. BPA had specifically asked Idaho Power for information related to the Exergy Wind resource, and received responses to data requests which stated that Exergy Wind is an independent wind developer and that the wind resource location was in Hagerman, ID with an installed capacity of 260 MW. *See* Idaho Power's Responses to BPA-IP-FY12-09 and BPA-IP-FY12-11, July 12, 2010, at 1.

BPA Staff has discussed this issue with parties from Idaho Power and believes the error in the data response was unintentional and not committed in bad faith. Had the Exergy Wind resource been properly identified during the discovery phase of this proceeding, BPA Staff would likely have had an opportunity to address the generic issue 5.4 regarding aggregation of PURPA resources. However, because this information was presented very late in this proceeding, there was insufficient time for BPA to fully explore whether Idaho Power's proffered aggregation of wind resources is appropriate under the 2008 ASCM. The aggregation and disaggregation of wind resources is likely to be a very complex issue that would be best served through open discussions in BPA workshops. Based on the information that Idaho Power has presented, BPA preliminarily finds that Idaho Power's treatment of the Exergy Wind resource is not patently inconsistent with the ASCM. Thus, BPA will permit Idaho Power to retain the Exergy Wind resource as a new resource addition for this ASC Report *only*. However, BPA expressly preserves the right to more fully develop its position on the proper treatment of new resources that have been aggregated or disaggregated in order to meet state PURPA requirements in future ASC Review Processes. Consequently, BPA's decision to permit the inclusion of the Exergy Wind resources in this ASC Report should not be construed as agreement by BPA on the proper treatment of aggregated or disaggregated PURPA resources under the 2008 ASCM.

Decision:

Idaho Power's Exergy Wind resource will be included as a new resource in Idaho Power's ASC for this ASC Report only; BPA will revisit the treatment of aggregated or disaggregated PURPA resources in the next ASC Review Process.

4.2.10 ASC Forecast Model Coal Escalator

Issue:

Whether Idaho Power used the correct fuel expense for the new resource Langley Gulch.

Parties' Positions:

Idaho Power believes Langley Gulch's fuel expense should be $65,967,520.

BPA's Position:

Fuel expense for Langley Gulch should be $43,299,388, and fixed transportation costs should be $6,769,781.

Evaluation of Positions:

In its Appendix 1, Idaho Power "hard coded" the fuel expense of $65,967,520 into the individual new resources tab cell F53, overriding the formula for that cell. The natural gas fuel price Idaho Power is using in its Langley Gulch fuel expense is $6.00/MMBtu, resulting in a total fuel cost of $59,197,739 when using the fuel cost formula for calculating fuel costs. In Idaho Power's hard-coded amount, Idaho Power included in its expense calculation $6,769,781 of fixed transportation costs. *See* Idaho Power's email Response to BPA's October 28, 2010 phone message to Idaho Power, October 29, 2010, at 1.

BPA believes Idaho Power's fixed transportation costs of $6,769,781 should be included with Langley Gulch's expenses; however, BPA believes that the fixed expenses should be included in "Other Power – Operations" cell F54. BPA also believes that in order to remain consistent with previous decisions, BPA should use the natural gas price forecast that is used in the BP-12 Initial Proposal for the new gas-fired resources at Langley Gulch. As an example, *See* Section 6.1.6. of the FY 2010-2011 Final ASC, PacifiCorp, at 87.

BPA will adjust the natural gas price forecast to the $4.39 midpoint FY 2012–2013 rate period forecast natural gas price and include the calculated fuel cost of $43,299,388 for the Langley

Gulch plant. Additionally BPA, will include the fixed transportation costs of $6,769,781 in Other Power – Operations so that the total included fuel costs (both fixed and variable) will be $50,069,169 in Idaho Power's individual new resources tab.

Decision:

BPA will use the FY 2012–2013 rate period natural gas price forecast of $4.39 and will include the $6,769,781 fixed natural gas transportation costs in Other Power – Operations.

Table 4.2.10-1: Langley Gulch Fuel Expenses

	Fuel Expense
As-Filed	65,967,520
Adjusted	43,299,388

	Other Power – Operations
As-Filed	2,500,000
Adjusted	9,269,781

4.2.11 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 revision updates 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.

4.2.12 ASC Forecast Model Coal Escalator

Issue:

Whether BPA is using the appropriate coal escalator in the ASC Forecast Model.

Parties' Positions:

The Idaho Power and IPUC believe that the coal escalator used in the ASC Forecast Model is inappropriate.

BPA's Position:

BPA is using the coal escalator prescribed by the 2008 ASCM.

Evaluation of Positions:

On August 24, 2010, Idaho Power questioned BPA's use of the Global Insight coal escalator, which projected a 12.1% decrease in the price of coal between 2009 and 2010. *See* Idaho Power's Issue List to BPA, August 24, 2010, at 2. Idaho Power claims that the use of a negative escalator in general, and the magnitude of the decrease, is inapplicable to Idaho Power, and therefore use of it is unreasonable. *Id.*

On May 27, 2010, Idaho Power requested an explanation for the Global Insight coal escalator. *Id.* Idaho Power stated that it obtains the majority of coal for its coal-fired production plants on long-term contracts. *Id.* Based on these contracts, Idaho Power argued that it does not foresee any decrease in prices during the time frame identified in the Forecast Model. *Id.* Idaho Power is concerned that an index is being used that may not be completely understood and is not applicable to all parties who are filing ASCs with BPA. *Id.*

The IPUC agrees with Idaho Power's position that the use of the Global Insight's projected decrease of 12.1% coal escalator is inappropriate. *See* Idaho Public Utilities Commission comments on Idaho Power's August 24, 2010 Issue List FY12 Idaho Power, at 1. The IPUC adds that it believes that the coal escalator of −12.1% is inappropriate for utilities that have entered into long-term contracts to purchase coal for power plants. *Id.*

BPA disagrees. BPA is required under the 2008 ASCM to use Global Insight as the source of data for all escalators used in BPA's ASC Forecast Model, except for natural gas, electric wholesale market prices and for line items designated as "constant." *See* 18 C.F.R. § 301.4(a)(4); *see also* BPA's response to Idaho Power Issue List, September 3, 2010, at 3. When the ASC Forecast Model was prepared for the FY 2012–2013 ASC reviews, BPA Staff used Global Insight's most recent coal forecast. *Id.* The fact that Global Insight's forecast may not match Idaho Power's internal forecast is not relevant for purposes of determining ASC. *Id.* The 2008 ASCM is clear that the source of escalation for coal fuel will be Global Insight. *Id.* Use of Global Insight as the source for the ASC Forecast Model's escalation was discussed during the consultation on the 2008 ASCM and approved by the parties. *See* 2008 ASCM ROD, at 39. The only approved grounds for changing the source of escalation from Global Insight to another forecasting source is that an escalator is no longer "available." *See* 18 C.F.R. § 301.4(a)(7).

Since BPA is under the guidance of the 2008 ASCM to forecast the FY 2012–2013 ASCs, BPA will continue to use the coal escalator as is used by BPA for the BP-12 Rate Case.

Decision:

BPA will use the same vintage forecast coal escalator as used in the BP-12 Rate Proceeding.

5 GENERIC ISSUES

5.1 Introduction

In addition to the above-noted issues specific to the determination of Idaho Power'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").[5]

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

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

5.2 NLSL Issues

5.2.1 Rebuttal Presumption for NLSLs

Issue:

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

Parties' Positions:

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

BPA's Position:

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

[5] 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.

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

<u>Issue:</u>

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

<u>Parties' Positions:</u>

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.*

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

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.

<u>Evaluation of Positions:</u>

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

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

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

16 U.S.C. § 839a(13).

This statutorily prescribed exclusion has been reflected in BPA's 1981, 1984, and 2008 ASCMs through a prescribed treatment contained in ASCM footnotes or endnotes. Under the 2008 ASCM, the method for excluding resource costs sufficient to serve a utility's NLSL is found in Endnote d.

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

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

BPA disagrees. First, the IOUs are incorrect to assert that a final NLSL determination is necessary for calculating the cost of serving an NLSL. There are many instances where BPA may be able to make this calculation prior to the formal NLSL determination. For example, if BPA and an exchanging utility agree that a load is likely to become an NLSL after the Final ASC Reports are issued, but before the end of the Exchange Period, BPA and the utility can agree on the size of the load in order for BPA to determine the adjustment to the utility's ASC.

Second, even if the utility and BPA are unable to agree on the size of a potential NLSL, it is still reasonable for BPA to make this estimate itself and then calculate the resource costs to exclude from ASC if and when the load becomes an NLSL. BPA is statutorily required to exclude from a utility's ASC the cost of resources sufficient to serve an NLSL. *See* 16 U.S.C. § 839c(c)(7)(A). If an NLSL is identified in a utility's service territory during an Exchange Period, BPA must be able to make an adjustment to the utility's ASC to implement the requirements set forth in section 5(c)(7) of the Northwest Power Act. Using a projected NLSL in the Final ASC report accomplishes this objective because it provides BPA with a predefined amount of resource costs to remove from the utility's ASC as a result of BPA's identification of an NLSL.

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

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

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

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

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

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

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

Decision:

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

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

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

5.2.3 Request for a Practical NLSL Determination Process

Issue:

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

Parties' Positions:

Idaho Power, PacifiCorp, Portland General, and Puget each provided comments on the Draft ASC Reports requesting that BPA implement a fair and reasonable process in which to evaluate and determine NLSLs before NLSL determinations were made and used in ASCs. *See* IPC Comments at 1-2; PAC Comments at 1-2; PGE Comments at 1-2; and PSE Comments at 2.[6]

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

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

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' RHWM ASCs.

Parties' Positions:

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

BPA's Position:

Conservation costs should be included in COUs' RHWM ASCs.

Evaluation of Positions:

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

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

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

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

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

(2) Determine the RHWM Exchange Load.

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

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

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

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

18 C.F.R. § 301.4(g).

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

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

Where:

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

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

CHWM Contract Amendment ROD at 8.

BPA implements this language pursuant to the following simplified formula:

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

NewResMWh = Above-RHWM Load

NewRes$ = Fully Allocated Costs × Above-RHWM Load

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

For ASC purposes:

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

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

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

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

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

IOU TRM Comments at 3.

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

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

2. If projected Contract System Load is greater than or equal to the utility's RHWM, then the conservation has not reduced the power purchased at Tier 1 rates, so all

of the conservation is serving Tier 2 Load. *Id.* at 4. Therefore, all conservation costs of the RHWM utility are included in NewRes$.

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

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

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

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

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

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

Id. at 4.

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

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

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' RHWM ASCs for several reasons.

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

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

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

Decision:

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

5.4 Re-Bundling of Disaggregated New Resource Projects

Issue:

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

Parties' Positions:

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

BPA's Position:

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

Evaluation of Positions:

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

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

Idaho Public Utilities Commission (IPUC) as evidence that developers may be disaggregating projects to utilize the published avoided cost rates. *Id.*

Although BPA understands the parties' concerns with the aggregation and disaggregation of new resources, it is unclear to BPA what this comment has to do with the decisions BPA has reached in the Draft ASC Reports. In raising this issue, the parties do not cite to any specific issue or decision BPA discussed in the Draft ASC Reports. Nor is BPA aware of any Issue List or other filing in these proceedings that addressed the concerns raised by the parties in their comments. As best BPA can tell, the parties' comment amounts to a request for BPA to make an advisory opinion on the ASC treatment of resources that have been aggregated or disaggregated for purposes of obtaining favorable PURPA rates. BPA declines to do so for two reasons.

First, inasmuch as the parties' comment is a "general" comment on BPA's review of the ASCs and is not aimed at challenging any specific decision or issue addressed in the Draft ASC Reports, BPA is not required to respond to the parties' comments. *See* Rules of Procedure at § 3.7.1.2 ("The Utility and parties must specifically identify the decision or statement from the Draft Utility ASC Report that is being addressed in the comments. Comments that contain generic statements regarding a Utility's ASC may not be considered by BPA.").

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

Decision:

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.

<u>Decision:</u>

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

6 FY 2012–2013 ASC

Idaho Power's ASC for FY 2012–2013, prior to the addition of new resources and NLSLs taking power either before or during the Exchange Period, is $45.79/MWh. This result is based on adjustments made to Idaho Power's ASC Filing.

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

Table 6.1: ASC Summary Table

Exchange Period ASC Summary Table				
	***Prior to* the Exchange Period**		***During* the Exchange Period**	
	No New Resources	Group 1 only	Group 2 only	Both Groups 1&2
ASC w/o NLSL (Customer B)	$45.79	$46.97	$48.24	$49.44
ASC w/NLSL (Customer B)	$45.55	$46.73	$47.95	$49.16

7 REVIEW SUMMARY AND REQUEST FOR COMMENTS

The FY 2012-2013 ASC Review Processes are complete with the publication of the ASC Final 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 Idaho Power for FY 2012 and FY 2013.

This Final ASC Report is BPA's determination of Idaho Power's FY 2012 and FY 2013 ASC based on information and data provided by Idaho Power, 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 Idaho Power'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 Idaho Power's ASC.

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

<u>/s/ Stephen J. Wright</u>

Administrator and Chief Executive Officer

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9 ATTACHMENT A

IX. AVERAGE SYSTEM COST METHODOLOGY APPENDIX 1 ENDNOTES

a/ Contract System Costs must reflect the costs and the revenues arising from conservation and/or retail rate schedules.

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

The return on equity (ROE) used in the WCC calculation will then be grossed up for Federal income taxes at the marginal Federal income tax rate using the following formula to determine the percentage increase in the ROE used for ASC determination:

FIT Adder = {(WCC – (Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1-Federal Tax Rate)}

The sum of the FIT Adder plus the ROE equals the Federal income tax adjusted ROE (TAROE). The TAROE will replace the ROE in the WCC calculation to determine a Federal income tax adjusted weighted cost of capital (TAWCC). The TAWCC will be multiplied by the total rate base from Schedule 1 to determine the return component on Schedule 2.

For Utilities that do not use depreciation for Jurisdictional rate setting, the return will be equal to the weighted cost of debt times the rate base included in the ASC filing.

c/ 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 will 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 must be functionalized according to the PTDG ratio.

d/ The cost of additional resources sufficient to serve any New Large Single Load (NLSL) that was not contracted for, or committed to, prior to September 1, 1979, is to be determined as follows:

(1) To the extent that any NLSLs are served by dedicated resources at the cost of those resources, including applicable transmission;

(2) In the amount that NLSLs are not served by dedicated resources, at Bonneville's New Resources (NR) rates as established from time to time pursuant to section 7(f) of the Northwest Power Act, and as applicable to the Utility, and applicable Bonneville

transmission charges if transmission costs are excluded in the determination of Bonneville's NR rate, to the extent those costs are recovered by the Utility's retail rates in the applicable Jurisdiction; and

(3) To the extent that NLSLs are not served by dedicated resources plus the Utility's purchases at the NR rate, the costs of the excess load will be determined by multiplying the kilowatt-hours not served under paragraphs (d)(1) and (d)(2) above, by the cost (annual fixed plus variable cost, including an appropriate portion of general plant, administrative and general expense and other items not directly assignable) per kilowatt-hour of all resources and long term power purchases (five years or more in duration), as allowed in the regulatory Jurisdiction to establish retail rates during the Exchange Period, exclusive of the following resources and purchases: (a) purchases at the NR rate; (b) purchases at the PF Exchange rate, pursuant to section 5(c) of the Northwest Power Act; (c) resources sold to Bonneville, pursuant to section 6(c)(1) of the Northwest Power Act; (d) dedicated resources specified in endnote d(1) of this Methodology; (e) resources and purchases committed to the Utility's load as of September 1, 1979, under a power requirements contract or that would have been so committed had the Utility entered into such a contract; and (f) experimental or demonstration units or purchases therefrom. Transmission needed to carry power from such generation resources or power purchases must be priced at the average cost of transmission during the Exchange Period.

The paragraphs (d)(1) through (d)(3) will determine the Base Period cost of resources used to serve NLSLs. Bonneville will escalate the Base Period cost of resources used to serve NLSLs to the Exchange Period using the following steps:

i. Escalate the components of the Base Period fully allocated resource costs to the Exchange Period using the general method for escalation of all Base Period costs.

ii. Adjust the projected resource costs by the projected transmission costs.

iii. Add the fully allocated costs for major resource additions/retirements to the Exchange Period fully allocated costs.

iv. The cost to serve NLSLs will change when the ASC changes due to resource additions/retirements.

v. The Exchange Period NLSL load will equal the Base Period NLSL load.

e/ The losses will be the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load. The distribution loss can be measured using one of the following 3 methods:

Method 1, Distribution Loss Study: Losses will be established according to a study (engineering, statistical and other) that is submitted to Bonneville by the Utility that will be subject to review by Bonneville. This study must be in sufficient detail so as to accurately identify average distribution losses associated with the Utility's total load, excluded loads, and the residential load. Distribution losses must include losses associated with distribution substations, primary distribution facilities, distribution transformers, secondary distribution facilities and service drops.

Method 2, Revenue Grade Meters: If a Utility does not have a loss study, but it has sufficient revenue grade meters in its distribution system, Bonneville will permit the Utility to directly measure its distribution losses subject to Bonneville review and approval. A Utility that does not possess the capability to directly measure its distribution losses will be required to submit a distribution loss study every seven years.

Method 3, Default: If a Utility does not have a current loss study or grade meters, Bonneville will accept the following method for determining a Utility's distribution loss factor.

i. Calculate a 5-year average total system loss factor, using data from the Base Period plus the preceding 4 years. IOUs will use data from the FERC Form 1. COUs will use a comparable data source.

ii. From this 5-year total system loss factor, subtract the loss factor for Bonneville's transmission system.

iii. The resulting loss factor will be deemed to be the exchanging Utility's distribution loss factor for calculating Contract System Load and exchange loads under the REP.

f/ Cash working capital (CWC) is a ratemaking convention that is not included in the FERC Form 1, but is part of all electric utility rate filings as a component of rate base. For determining the allowable amount of cash working capital in rate base for a Utility, Bonneville will allow no more than 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and Public Purpose Charge.

g/ Conservation costs are costs of energy audits and actual or planned load reduction resulting from direct application of a conservation measure (Northwest Power Act, section 3(19)(B)) by means of physical improvements, alterations, devices, or other installations that are measurable in units. Conservation costs funded by the Utility will be functionalized to Production in the Utility's Average System Cost. Conservation costs incurred to promote changes in consumer behavior including costs attributable to brochures, advertising, pamphlets, leaflets, and similar items will be functionalized by Direct Analysis with a default to Distribution/Other. Conservation surcharges imposed pursuant to section 4(f)(2) of the Northwest Power Act or other similar surcharges or penalties imposed on a Utility for failure to meet required conservation efforts will also be functionalized to Distribution/Other. Conservation and associated costs must be generally consistent with the Northwest Power and Conservation Council's resource plan as determined by Bonneville's Administrator.

h/ Public Purpose Charges collected by Utilities and distributed to independent third party non-profit organizations or state and local entities (recipient organizations) for the purposes of acquiring conservation and renewable resources shall be determined on a utility-by-utility basis through Direct Analysis. The ASC Methodology will only allow the costs of conservation and renewable resource development, acquisition and implementation. Allowable costs include costs associated with energy audits and advertising and promotion of conservation and renewable resources.

In order to be included in Contract System Costs, the renewable resources acquired by the recipient must be included in the Utility's Integrated Resource Plan or similar document and, in the case of dispatch able resources, must be included in the Utility's resource stack. Bonneville will treat expenditures of Public Purchase Charge funds similar to Utility conservation costs.

i/ If a Utility has a ruling from its Regulatory Body that separates its transmission and distribution lines using the Commission's seven factor test contained in Order 888, as amended by Order 890, and its FERC Form 1 filing is consistent with the Regulatory Body's order, the Utility will include the transmission-related costs and wheeling revenues directly from its FERC Form 1 filing. However, if a Utility is not required to file a FERC Form 1, or it has not received an order from its Regulatory Body separating its lines between transmission and distribution, then it must perform a Direct Analysis on its transmission costs and wheeling revenues. The Direct Analysis must allocate transmission costs and wheeling revenues so that only the costs and revenues of transmission lines rated at 115kV or above are included as transmission. Alternatively, the Direct Analysis may use the Commission's seven factor test for separating transmission and distribution lines to determine the costs attributable to transmission.

j/ All revenues associated with the production and transmission function of a Utility will be functionalized to production or transmission respectively.

BONNEVILLE POWER ADMINISTRATION

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