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 2014–2015

FINAL
AVERAGE SYSTEM COST REPORT

NorthWestern Energy

July 2013

FY 2014–2015

FINAL
AVERAGE SYSTEM COST REPORT

FOR

NorthWestern Energy
Docket Number: ASC-14-NW-01

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

July 2013

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1 FILING DATA

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

Parties to the Filing:

Investor-Owned Utilities (IOUs):
- Avista Corporation (Avista)
- Idaho Power Company (Idaho Power)
- PacifiCorp
- Portland General Electric (PGE)
- 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 Utility Commission of Oregon (OPUC)

Average System Cost Base Period: Calendar Year (CY) 2011

Effective Exchange Period: Fiscal Years (FY) 2014–2015, October 1, 2013 – September 30, 2015

Statement of Purpose:

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"). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to the Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at a rate established pursuant to section 7(b) of the Act. 16 U.S.C. § 839c(c)(1); 16 U.S.C. § 839e(b)(1). The benefits determined under the REP are passed through directly to the exchanging utilities' residential and farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act grants BPA's Administrator the authority to determine utilities' 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.

BPA has conducted an ASC review to determine NorthWestern's ASC for FY 2014–2015 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). As noted above, the utilities' ASCs are used in the BP-14 Rate Case to calculate the utilities' benefits, which are then distributed through the REP.

This FY 2014–2015 Final Average System Cost Report (Final ASC Report) describes the process and evaluation used to implement to the 2008 ASCM and the results of BPA's ASC Filing review.

For more information regarding the 2008 ASCM, please refer to the Federal Energy Regulatory Commission's final ruling and the *2008 ASCM*, 18 C.F.R. Part 301 (2009), available at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Documents/2008%20FERC%20Published%20ASCM_FRN_74_FR_47052-01_9-30-09_1741.pdf, and the *Average System Cost Methodology Final Record of Decision (2008 ASCM ROD)*, June 30, 2008, available at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx.

General information regarding the ASC Review Process can be found at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx.

NOTE: If the filing utility or an intervenor wished to preserve any issue regarding a BPA Final ASC Report for subsequent administrative or judicial appeal, it must have raised such issue in its comments on the Draft ASC Report. If a party failed to do so, the issue is waived for subsequent appeal. *See* Rules of Procedure for BPA's ASC Review Processes, § 3.6.1.3 ("Rules of Procedure").

2 AVERAGE SYSTEM COST SUMMARY

2.1 NorthWestern Energy Background

NorthWestern Energy (NorthWestern) is an investor-owned utility, engaged in the production, transmission and distribution of electricity and in the distribution of natural gas (and other energy-related businesses) throughout a service territory consisting of Montana, Nebraska and South Dakota. The company, based in Sioux Falls, South Dakota, serves approximately 107,600 square miles in Montana, which represents 73 percent of Montana's land area.

NorthWestern provides both natural gas and electric service to over 673,200 customers. The focus of this report concerns NorthWestern's electric system in Montana, with about 342,000 electric customers served by 6,900 miles of transmission lines and 17,500 miles of distribution lines.

The company contracts approximately 89 percent of its energy requirements through a variety of long-term and short-term purchases. Details of NorthWestern's 2011 electric supply are shown in the table below.

NorthWestern Energy 2011 Montana Electric Generation and Energy				
Type	**Capacity (MW)**	**Percent**	**Energy (MWh)**	**Percent**
Coal	242	52	1,390,256	19
Gas	215	46	331,334	5
Small Plants	9	2	648	0
Purchases			5,561,363	76
Total	**466**	**100**	**7,283,601**	**100**

NorthWestern Energy, 2011 FERC Form 1, February 27, 2012.

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 for COUs, the most recent audited financial statements (Annual Reports) and for both, the underlying accounting system data. For purposes of this FY 2014–2015 filing period, the Base Period is CY 2011 (January 1, 2011 – December 31, 2011). The submitted information includes the "Appendix 1," an Excel-based workbook populated with financial and load data used in calculating the Base Period ASC.

The table below summarizes the CY 2011 Base Period ASC based on (1) the information contained in NorthWestern's June 4, 2012, ASC Filing, including any errata corrections

("As-Filed"), and (2) as adjusted by BPA in this Final ASC Report. This table does not reflect the Exchange Period (defined below) ASC, which is noted in subsequent tables.

Table 2.2-1: CY 2011 Base Period ASC
(Results of Appendix 1 calculations)

	June 4, 2012 As-Filed	**July 24, 3012 Final ASC Report**
Production Cost	$380,073,427	$380,073,427
Transmission Cost	$40,165,263	$40,165,263
(Less) NLSL Costs	$0	$0
Contract System Cost (CSC)	**$420,238,690**	**$420,238,690**
Total Retail Load (MWh)	5,912,124	5,901,610
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	5,912,124	5,901,601
Distribution Losses	182,093	340,523
Contract System Load (CSL)	**6,094,218**	**6,242,133**
CY 2011 Base Period ASC (CSC/CSL)	**$68.96/MWh**	**$67.32/MWh**

2.3 FY 2014–2015 Distribution Loss Factor

The 2008 ASCM requires a utility to include with its ASC Filing a current distribution loss analysis as described in Endnote e. *See* 18 C.F.R. § 301, End. e.

The losses are the distribution energy losses occurring between the transmission portion of the utility's system and the meters measuring firm energy load. The distribution losses can be measured using one of the methods outlined in Endnote e of the 2008 ASCM: (1) a loss study, (2) revenue grade meter readings, or (3) calculating a five-year average total system loss factor using data from the FERC Form 1 or comparable data source.

BPA Staff reviewed NorthWestern's As-Filed Appendix 1 Distribution Loss Factor of 3.08 percent and the supporting calculations. For the purposes of this Final ASC Report, BPA Staff determined to use a Distribution Loss Factor of 5.77 percent. See Sections 4.1.1.1 and 4.2.1.1 for background information and discussion concerning NorthWestern's Distribution Loss Factor.

2.4 FY 2014–2015 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, 2014. For purposes of this FY 2014–2015 ASC Review Period, the Exchange Period is October 1, 2013, to September 30, 2015 ("Exchange Period").

A utility's As-Filed Exchange Period ASC may increase or decrease by the time of the Final ASC Report because of adjustments made during the ASC Review Process. For all utilities, BPA updates its natural gas and market price forecasts, which factor into the escalation calculations BPA uses in developing a utility's Exchange Period ASC. For calculating the FY 2014-2015 Exchange Period ASC, gas prices decreased slightly and market prices rose slightly from the BP-14 Rate Case Initial Proposal. BPA also updates escalators used in the ASC Forecast Model that rely on data from Global Insight, including its coal escalators, which decreased from the BP-14 Rate Case Initial Proposal. For the COUs only, BPA updated the RHWMs and the associated Tiered Rates. See the "Inputs" and "Tiered Rates" tabs of the ASC Forecast Model for the utility's (1) As-Filed and (2) BPA-Adjusted models for additional details.

Table 2.4-1 identifies the Exchange Period ASC as filed by the utility on June 4, 2012, including errata corrections if filed, and as adjusted by BPA for this Final ASC Report. The ASC shown will be the utility's ASC for the entire Exchange Period unless the utility acquires (or loses) a major resource as defined by the 2008 ASCM, subject to the conditions in Section 2.5 of this Report, or the utility makes a New Large Single Load adjustment as described in Section 2.6.

Table 2.4-1: Exchange Period FY 2014–2015 ASC ($/MWh)
With No New Resource Additions

Date	June 4, 2012 As-Filed	July 24, 2013 Final ASC Report
FY 2014–2015	69.63	68.67

2.5 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 and the end of the Exchange Period. 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 Period 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 3.2.14 of this Final ASC Report.

For ASC calculation purposes, a new resource adjustment may be included in the utility's ASC at the commencement of the Exchange Period if such new resource becomes commercially operational (or ceases production) after the Base Period ends, but *before* the Exchange Period begins. In order to be included in the utility's Exchange Period ASC, a New Resource Attestation must be received by BPA no later than the tenth (10th) business day after the Exchange Period begins.

Table 2.5-1 below summarizes the new major resource additions, prior to any NLSL adjustments, that have become commercially operational prior to the beginning of the Exchange Period (*i.e.*, January 1, 2012 – September 30, 2013).

Inadvertently, NorthWestern's As-Filed ASC Filing did not reflect its proposed new resource, Spion Kop, for purposes of calculating NorthWestern's Exchange Period ASC. As expected, Spion Kop came on line in December, 2012, prior to the beginning of the FY 2014–2015 Exchange Period.

Table 2.5-1: New Resource Additions Coming On Line
***Prior to* the Exchange Period ($/MWh)**

As-Filed FY 2014–2015 Exchange Period ASC				
Resource	**Spion Kop**	**N/A**	**N/A**	**N/A**
Expected On Line Date	12/01/2012			
Delta*	0			

Final ASC Report FY 2014–2015 Exchange Period ASC				
Resource	**Spion Kop**	**N/A**	**N/A**	**N/A**
On Line Date	12/01/2012			
Delta*	1.98			

*The Delta is the incremental change in the ASC as new resources come on line. NorthWestern's As-Filed Appendix 1 did not include the Spion Kop new resource on the New Resources – Individual Tab or in the forecast model.

Resources that commence commercial operation during the Exchange Period are normally reflected in the ASC calculation following receipt by BPA of the utility's New Resource Attestation. Table 2.5-2 below summarizes the new major resource additions (prior to any NLSL adjustments) that are projected to become commercially operational and major resource reductions that will cease to be commercially operational during the Exchange Period (*i.e.*, October 1, 2013 – September 30, 2015).

Although the 2008 ASCM permits a utility's ASC to be adjusted to reflect the inclusion of a major new resource during the Exchange Period, as part of the 2012 Residential Exchange Program Settlement Agreement, BPA Contract No, 11PB-12322 (2012 REP Settlement Agreement), all six regional investor-owned utilities agreed to waive this right: "Each IOU waives . . . the right to include in its ASC . . . the cost of any major resource addition forecasted to occur during the Exchange Period as allowed by the ASC Methodology." 2012 REP Settlement, § 6.4. Nevertheless, for informational purposes, BPA has retained Table 2.5-2 in the ASC Report because the 2012 REP Settlement is currently being challenged in the U.S. Court of Appeals for the Ninth Circuit. BPA intends to continue to identify major resource additions in its Draft and Final ASC Reports until such time as all legal challenges to the 2012 REP Settlement have been resolved. The final FY 2014–2015 ASC calculation shown in Section 6 of this Report *does not* include any adjustment for new resources during the Exchange Period for setting rates for the FY 2014–2015 Rate Period.

NorthWestern has no major new resources coming on line during the FY 2014–2015 Exchange Period.

Table 2.5-2: New Resource Additions Coming On Line *During* the Exchange Period ($/MWh)

As-Filed FY 2014–2015 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On Line Date				
Delta*				

Final ASC Report FY 2014–2015 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On Line Date				
Delta*				

*The Delta is the incremental change in the ASC as the new resources come on line. See the "New Resources" and "ASCs" tabs in the ASC Forecast Model for NorthWestern's As-Filed and BPA-Adjusted Appendix 1s.

2.6 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 the Final Interpretation and Implementation of Endnote d(3) of the 2008 ASC Methodology (February 2012).

NLSLs are not determined in ASC review proceedings. Instead, NLSLs are identified through a separate process conducted by BPA's NLSL Staff, which is 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.

NorthWestern has no NLSLs on record or under review, and therefore no NLSL resource costs will be removed from its ASC. Pursuant to Montana Code Annotated 2011, § 69-8-201, there are electricity supply restrictions on potential retail customers with an average monthly demand of 5,000 or more kilowatts and who are not purchasing electricity supply service from a public utility on October 1, 2007. Such retail customer may not purchase electricity supply service from a public utility. Under subsection 1(b) of the Montana code, however, such retail customer may request service from a public utility if the customer can demonstrate that providing service will not adversely impact the public utility's other customers over the long term as determined by the commission. Please refer to § 69-8-201 for additional information and restrictions related to this electricity supply service. BPA Staff has been advised that NorthWestern is not currently aware of any retail customer requesting new service under subsection 1(b) of the Montana code now or through the end of the Exchange Period.

Table 2.6-1: New Large Single Loads Under Review

As-Filed FY 2014–2015 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
N/A	N/A

Final ASC Report FY 2014–2015 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
N/A	N/A

Table 2.6-2: New Large Single Loads that Begin Taking Power *Prior to* the Exchange Period

As-Filed FY 2014–2015 Exchange Period ASC				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Final ASC Report FY 2014–2015 Exchange Period ASC				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Table 2.6-3: New Large Single Loads that Begin Taking Power *During* the Exchange Period

As-Filed FY 2014–2015 Exchange Period ASC				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Final ASC Report FY 2014–2015 Exchange Period ASC				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

2.7 NLSL Formula Rate

During two separate customer workshops held on February 2 and April 11, 2012, BPA Staff proposed a formula rate calculation for removing resource costs from a utility's ASC when an NLSL occurs during the Exchange Period. The NLSL formula rate was developed to mitigate two issues that arise when a large industrial/commercial load has been determined to be an NLSL and has a determined NLSL start date.

In previous Exchange Periods, BPA calculated the costs of serving a prospective NLSL in the ASC Review Process based on forecasts of the projected NLSL MWh and a start date as provided by the filing utility. BPA Staff would then calculate two ASCs for the utility: an ASC with the NLSL coming on line as scheduled (with an associated reduction in ASC) and an ASC with the NLSL not coming on line (and no associated reduction in ASC). This approach for determining the costs of service to an NLSL, however, led to additional administrative and calculation issues. First, new NLSL(s) start dates may differ from the forecast; and second, the actual MWh amounts of the NLSL may differ substantially from forecast amounts contained in the Final ASC Report.

To address the potential disconnect between the forecast amount and start date of an NLSL, BPA Staff proposed a formula rate. In late April 2012, parties submitted formal responses to the

NLSL topic discussed at the February 2 and April 11 workshops. Avista, Idaho Power, NorthWestern, PGE, PacifiCorp, and Puget all submitted comments in support of the NLSL Formula Rate. With the exception of PGE, all the parties agreed with BPA's formula rate calculation proposal to calculate a utility's ASC when a new NLSL materializes. PGE, in its response, commented on issues outside the scope of the proposed NLSL Formula Rate.

For purposes of the Final ASC Reports, no utility identified potential NLSLs that would begin service prior to or during the FY 2014–2015 Exchange Period, January 1, 2012 through September 30, 2015. However, in the event a utility learns it will begin to serve an NLSL during this period, even though the NLSL is not identified herein, BPA Staff will review and evaluate the NLSL and, as necessary, calculate a new ASC using the inputs and formula method as defined below:

$$\text{ASC} = \frac{\text{Contract System Cost} - (\text{Cost of Serving NLSL} * \text{Actual New NLSL MWh})}{\text{Contract System Load} - \text{Actual New NLSL MWh}}$$

Tables 2.7-1 and 2.7-2 show the inputs necessary to calculate a utility's Exchange Period ASC using the above NLSL Formula Rate. The tables include the inputs Contract System Cost ($), Cost of Serving NLSL ($/MWh), and Contract System Load (MWh). A utility's Contract System Cost and Cost of Serving NLSL will change with each new resource addition. Therefore, Table 2.7-1 provides the various combinations of new resource additions possible and the corresponding Contract System Cost and Cost of Serving NLSL. Table 2.7-2 contains the utility's Contract System Load, which remains unchanged with the addition of new resources.

Spion Kop came on-line prior to the start of the FY 2014-2015 Exchange Period. However, because of the legislative requirements for serving retail loads in excess of 5MW (*see* Section 2.6), BPA presumes no loads will qualify as an NLSL during the Exchange Period. As such, BPA is not calculating the cost to serve NLSLs for the utility at this time. BPA Staff has also been advised that NorthWestern is not currently aware of any retail customer requesting new service in excess of 5MW now or through the end of the Exchange Period.

Table 2.7-1: NLSL Formula Rate Inputs:
Contract System Cost & Cost of Serving NLSL

Inputs for both *Prior to* and *During* the Exchange Period			
	Timing of New Resource	**Contract System Cost**	**Cost of Serving NLSL**
Prior to	Spion Kop	N/A	N/A
During	No new resources coming on line	N/A	N/A

Table 2.7-2: Formula Rate Input:
Contract System Load

FY 2014–2015 **Contract System Load**
N/A

3 FILING REQUIREMENTS

3.1 ASC Review Process – FY 2014–2015

Utilities' ASCs are established in ASC Review Processes. The ASC Review Processes for FY 2014–2015 began on June 4, 2012, with the submittal of ASC Filings by the following eight utilities: Avista, Clark, Idaho Power, NorthWestern, PacifiCorp, PGE, Puget, and Snohomish. 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 public web site, Secure REP Web Site and via email. Prior to the June 4, 2012, filing deadline, the utilities posted 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' ASC Filings. 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 ASC Filings.

Draft ASC Reports were issued on November 14, 2012, for each of the eight utilities. On December 14, 2012, BPA Staff held a clarification workshop to review and discuss the Draft ASC Reports. Thereafter, the utilities and intervenors had the opportunity to request oral argument before BPA's Administrator. No request was received by the February 1, 2013, deadline. Finally, utilities and intervenors could submit comments on the Draft ASC Reports through April 10, 2013. *See* Sections 4 and 5 to review comments, if any, submitted by the utilities and intervenors.

This Final ASC Report reflects BPA's findings and final decisions from its review of NorthWestern's ASC Filing, and addresses the issues and questions raised by the utility, intervenors, and BPA Staff during the ASC Review Process.

For details of the ASC Review Process and guidelines, please see the *ASCM Rules of Procedure for the ASC Review Process* (*Rules of Procedure*) available at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx.

Final ASC Reports for each utility are available at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/FY-14-15-ASC-Utility-Filings.aspx.

3.2 Explanation of Appendix 1 Schedules

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

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

3.2.1 Schedule 1 – Plant Investment/Rate Base

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

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

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

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

3.2.2 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.[1]

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.

3.2.3 Schedule 2 – Capital Structure and Rate of Return

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

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

3.2.4 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.

3.2.5 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.

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

3.2.6 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.

3.2.7 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.

3.2.8 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 in 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.

3.2.9 Load Forecast

Each utility is required to provide a four-fiscal-year forecast beginning October 1 of the Base Year (FY 2012–2015) of its total retail load, as measured at the meter, and its qualifying residential and farm retail load, as measured at the retail meter. For the COUs only, the total retail forecast loads for the Exchange Period are the load forecasts determined by BPA under the Tiered Rate Methodology (TRM).

The total retail and residential and 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.

3.2.10 Distribution Loss Calculation

Each utility is required to measure its distribution losses using one of the methods described in Endnote e of the 2008 ASCM. *See* 18 C.F.R. § 301, End. e. The total retail and residential and farm load forecasts are adjusted for distribution losses (and NLSLs when appropriate).

3.2.11 Distribution of Salaries and Wages

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

3.2.12 Ratios

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

3.2.13 New Resources – 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). However, as part of the 2012 REP Settlement, the IOUs agreed to waive the right to include the costs of new resources in their ASCs during the Exchange Period. See Section 2.5 for a discussion of New Resource Additions.

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 3.2.14 of this Report.

3.2.14 Materiality – Individual and Grouped

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).

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.

BPA Staff 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 using the utility's adjusted Base Period ASC (per the Draft ASC Report) and forecast natural gas prices used by BPA in the BP-14 Rate Case Initial Proposal. BPA Staff will remove all resources and/or groups of resource additions that do not meet the materiality test(s).

- BPA Staff will not unilaterally regroup resources.

- The BP-14 Rate Case Initial Proposal's 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 meets 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 for the Final ASC Report is determined after considering the filing utilities' and other parties' comments, if any, on the Draft ASC Report, based on the foregoing instructions.

The materiality determinations provided herein are based on the utility's Base Period ASC (per the Draft Report) as adjusted through the ASC Review Process and reflect the natural gas price forecast from the BP-14 Rate Case Initial Proposal.

3.2.15 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). 16 U.S.C. § 839c(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 prescribed in Endnote d of the 2008 ASCM. *See* 18 C.F.R. § 301, End. d and the Final Interpretation and Implementation of Endnote d(3) of the 2008 ASC Methodology (February 2012).

3.2.16 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 not to 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 3.3 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 Group (PSR). For background information and details, see http://www.bpa.gov/news/pubs/PastRecordsofDecision/2009/TRM-12S-A-02.pdf.

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

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. BPA uses the following method 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 Final 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 the RHWM ASC:
    - Power purchases less than five years in duration.

- Total output of new resources may exceed the Above-RHWM Load:
    - The RHWM ASC does not specify removal of costs associated with this excess.

The RHWM ASC calculation methodology provides:

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

3.4 ASC Forecast

Once the Base Period ASC is calculated, BPA uses the ASC Forecast Model to escalate forward the Base Period ASC to the midpoint of the Exchange Period. 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 power 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-14 Rate Case. For additional background on the determination of Exchange Period ASCs, see the 2008 ASCM. 18 C.F.R. § 301.4.

3.4.1 Forecast Contract System Cost

Forecast Contract System Cost ("FCSC") includes a utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which are includable in and subject to the provisions of the 2008 ASCM. BPA escalates Base Period costs to the midpoint of the Exchange Period 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.

3.4.2 Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. Utilities are then allowed to include new plant additions and use 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).

3.4.3 Forecast Contract System Load and Exchange Load

As a part of its ASC Filing, each utility is required to provide a four-fiscal-year forecast of its total retail load, as measured at the meter, and its qualifying residential and farm retail load, as measured at the retail meter. For the COUs only, total retail forecast loads, as determined by BPA under the TRM, will be provided through the end of the Exchange Period. Also required is a distribution loss calculation as prescribed in the 2008 ASCM, Appendix 1, Endnote e. The total retail and the residential and farm load forecasts are adjusted for distribution losses and NLSLs when appropriate. The resulting load forecasts are the Contract System Load forecast and Exchange Load forecast, respectively.

3.4.4 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, revenues, and loads used to establish ASCs for the REP. BPA Staff began the FY 2014–2015 ASC Review Process of NorthWestern's ASC Filing in June 2012. During the interim period, various issues related to NorthWestern's ASC Filing were identified by BPA Staff in the BPA Issues and Clarification List (BPA Issues List); no other party raised issues. NorthWestern responded to each issue raised in the BPA Issues List. This Final ASC Report summarizes the findings of Staff's review of NorthWestern's ASC Filing, the BPA Issues List and NorthWestern's responses thereto, and any comments received during the Draft Report comment period.

BPA's ASC determination is limited to specific findings on issues identified for comment, with the exception of ministerial and mathematical errors. There may be additional issues that BPA has not identified for comment in this Final ASC Report. Acceptance of a utility's treatment of an item without comment does not signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASCM. Similarly, further experience under the 2008 ASCM may result in BPA adopting a modified or different interpretation of the 2008 ASCM in future ASC reviews.

Prior to the start of the FY 2014–2015 ASC Review Processes, BPA held workshops on February 2, 2012, and April 11, 2012, to discuss and evaluate new BPA-proposed procedures, policies, and topics that may affect future ASC Reviews. Topics for discussion included NLSL reviews and determinations; the NLSL Formula Rate; definitions of individual new resources for conservation and renewables; FERC accounting questions regarding wind reporting, generation statistics, distribution loss calculations, purchased power and sales for resale; and the treatment of items included under Other Expenses (FERC Account 557) when evaluating the Cash Working Capital calculation.

Following considerable review and discussion of these topics, the Parties and BPA Staff either resolved each issue or determined the issue was not significant enough to warrant a change in policy or procedure. Therefore, with exception of the NLSL Formula Rate (further described in Section 2.7) and the treatment of items included under other expenses (FERC Account 557) when evaluating the Cash Working Capital calculation (Section 5.2.1), BPA has no additional comments regarding the resolved issues and will not separately address them in this ASC Report. BPA and the Parties retain the right to bring any of the topics forward during a later review process.

Table 4-1 summarizes all direct adjustments BPA made to NorthWestern's Appendix 1 in this Final ASC Report as a result of BPA's review and evaluation. Supporting arguments for these adjustments may be found in the Decisions on Draft Report Resolved Issues and/or Decisions on Draft Report Unresolved Issues sections.

Although a utility's state, county, or municipal regulatory bodies, or the Commission, may allow a particular functionalization for 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.

Table 4-1: Summary of ASC Issues

Appendix 1 Schedule	**Adjustment**
Schedule 1 – Plant Investment/Rate Base	No direct adjustments.
Schedule 1A – Cash Working Capital	See Section 5.2, Generic Issues.
Schedule 2 – Capital Structure and Rate of Return	No direct adjustments.
Schedule 3 – Expenses	No direct adjustments.
Schedule 3A – Taxes	No direct adjustments.
Schedule 3B – Other Included Items	No direct adjustments.
Schedule 4 – Average System Cost	Direct adjustments: see Sections 4.1.1.1, 4.1.2.1 and 4.2.1.1.
Appendix 1 Supporting Worksheets	**Adjustment**
Forecast Loads	Direct adjustment: see Section 4.1.2.1.
New Resource Additions	Direct adjustment: see Section 4.1.2.2.
NLSL Calculation	No direct adjustments.
Wind Resources	No direct adjustments.
Tiered Rates	Updated. See Tiered Rates Tab of Appendix 1.
Salary and Wages	No direct adjustments.
Ratios	No direct adjustments.
ASC Forecast Model	**Adjustment**
Tier 1 Power Purchases from BPA	See Section 5.3.1, Generic Issues.
Calculation of ASC Delta for New Resource Additions	See Section 5.3.2 , Generic Issues.
PF Rates	Updated. See the PF_Rates Tab.
Purchased Power and Sales for Resale	Erratum correction. See Section 4.3.1.
Natural Gas and Market Prices	Erratum correction. See Section 4.3.2.
Cash Working Capital	Erratum correction. See Section 4.3.3.

4.1 Decisions on Draft Report Resolved Issues

During the ASC Review Process, BPA Staff raised the issues discussed in this section and the "Unresolved Issues" discussed in Section 4.2.1, below. NorthWestern responded to these issues in its September 21, 2012 Issue List response, and to the NorthWestern Draft ASC Report in two "Comment Letters" dated, respectively, April 9 and May 1, 2013. No other party raised issues with, or commented on NorthWestern's June 4, 2012, ASC Filing. BPA Staff considers the issues identified in this section resolved.

In the April 9 Comment Letter, NorthWestern advised that they concurred or agreed with BPA's draft decision for each of the three resolved issues. NorthWestern also did not have any comment on the unresolved issues discussed in Section 4.3 or the generic issues discussed in Section 5. However, with respect to the unresolved issue discussed in Section 4.2.1.1, below, the Alternative Distribution Loss Factor issue, NorthWestern asked that they be granted an extension of time, until May 1, 2013, to provide comment.

NorthWestern's May 1 Comment Letter provided a proposal to address the unresolved issue identified in Section 4.2.1.1. See Section 4.2.1.1. for a more detailed discussion of NorthWestern's comments and proposal.

4.1.1 Schedule 4 – Average System Cost

4.1.1.1 Calculation of Distribution Loss Factor

Issue:

Whether it is appropriate to use data supplied in NorthWestern's FERC Form 1 to calculate NorthWestern's distribution loss factor.

Parties' Positions:

NorthWestern agrees with BPA Staff that its FERC Form 1 data does not properly reflect the distribution losses that NorthWestern experiences on its system and agrees with BPA Staff's recommendation to not use the distribution losses reported in its FERC Form 1.

BPA Staff's Position:

In NorthWestern's Draft Report, BPA Staff stated that they believed that NorthWestern's reported losses in its FERC Form 1, and NorthWestern's allocation of its total system losses between regional and non-regional loads, did not properly reflect the losses that NorthWestern is experiencing on its system. BPA Staff requested NorthWestern correct any deficiencies in the data. Because there were fundamental anomalies in NorthWestern's distribution loss data as reported in the FERC Form 1, BPA Staff recommended not using the distribution loss data reported in NorthWestern's FERC Form 1s.

Since then, however, NorthWestern submitted its May 1 Comment Letter which provided a proposal to use a three-year average (2009-2011) of distribution losses calculated using adjusted FERC Form 1 data. Specifically, NorthWestern adjusted page 401 FERC Form 1 data to remove system balancing load and unbilled sales for all but NorthWestern's Montana jurisdictional sales and off system sales. NorthWestern also removed the generation, purchases, and sales to consumers in the Yellowstone National Park (YNP) and Sales to Ultimate Consumers, which includes unbilled sales (the estimated difference between the cyclical and calendar data) related to choice customers. In an effort to approximate the calculation prescribed by the ASCM "Default Method," (*i.e.*, Method 3 in Endnote e) NorthWestern performed these same series of calculations for years 2009, 2010 and 2011, and then computed a three-year average to arrive at a distribution loss calculation of 5.77 percent. Comparable data for 2007 and 2008 (to permit a five-year average per the ASCM default method) was not readily available. BPA acknowledges that this calculation provides a reasonable alternative distribution loss factor for NorthWestern for the FY 2014-2015 Review Period. Please refer to the discussion regarding distribution losses in Section 4.2.1.

Evaluation of Positions:

The 2008 ASCM requires a utility to include with its ASC filing a current distribution loss analysis as described in Endnote e, as follows. *See* 18 C.F.R. § 301 End. e.

> e/ The losses shall 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 shall be established according to a study (engineering, statistical and other) that is submitted to BPA by the Utility which will be subject to review by BPA. This study shall 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 shall 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, BPA will permit the Utility to directly measure its distribution losses subject to BPA 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, BPA 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 BPA'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.

18 C.F.R. § 301 End. e.

NorthWestern does not have a recent distribution loss study or revenue grade meters. As discussed above, if a current distribution loss study is not available, and if the utility does not have revenue grade meters, Endnote e requires a utility to calculate its distribution loss factor using an average distribution loss factor based on the losses submitted in the utility's previous five FERC Form 1s, beginning with the Base Period (e.g., CY 2007–2011). (Method 3 in Endnote e.)

In Response to Data Request BPA-NW-FY14-16, NorthWestern calculated its distribution loss factor using 2011 FERC Form 1 data. Load and loss data were obtained from "Electric Energy Account Montana Only" on page 450.1 (immediately following page 401.b) and were then adjusted to remove load associated with Yellowstone National Park (see Issue 4.1.2.1). NorthWestern calculated its net loss factor as follows:

Losses divided by Sales = Total Loss Factor
Total Loss Factor minus BPA Transmission Loss Factor = Net Loss Factor

Total Sales 5,916,006 MWh
Total Losses 74,526 MWh
74,526/5,916,006 = 1.26%

BPA Transmission Loss Factor 1.90%
1.26% – 1.90% = <u>(0.64%)</u>

In this data response, NorthWestern also performed three other distribution loss factor calculations using three- and five-year averaged data principally obtained from submittals to the Montana Public Service Commission. Net distribution loss factors obtained from these calculations were 1.95 percent, 2.07 percent, and 3.08 percent, all of which NorthWestern acknowledged were not reasonable.

Averaging NorthWestern's distribution losses based on its FERC Form 1s from CY 2007 through CY 2011 results in a distribution loss factor of only 1.95 percent. This distribution loss factor is substantially below all distribution loss factors submitted by other utilities and is 2.71 percent below the distribution loss factor approved by BPA in NorthWestern's FY 2012-2013 ASC filing (4.66 percent).

NorthWestern's reported losses in its FERC Form 1, and NorthWestern's allocation of its total system losses between regional and non-regional loads, do not properly reflect the losses that NorthWestern is experiencing on its system. Under the 2008 ASCM, BPA must make an independent determination of "the appropriateness of Contract System Loads." ASCM Procedural Rules § 3.2.2. Based on BPA independent review, there is a systemic issue with the manner in which NorthWestern reports and allocates losses in the FERC Form 1.

For example, reported losses in NorthWestern's FERC Form 1 have dropped from 451,000 MWh in 2010 to 152,000 MWh in 2011, a decline of approximately 66 percent. In addition, the percent of total system losses NorthWestern attributes to its within-region power sales also changed dramatically between CY 2010 and CY 2011. In 2010, NorthWestern states that 82 percent of its total system losses were attributable to its within-region power sales (370,000 MWh). However, for CY 2011, NorthWestern states that only 49 percent of its total system losses are attributable to within-region sales (75,000 MWh). BPA has evaluated the losses reported by other utilities in their FERC Form 1s and has not seen similar variations.

BPA Staff had requested additional review by NorthWestern on the losses it included in the 2011 FERC Form 1 and on several occasions in previous ASC Review Processes. Although NorthWestern recognized that there was a problem with the FERC Form 1 input data, it had been unable to identify the cause of such anomalous and varied results in its distribution loss factor calculations. Because the distribution losses NorthWestern is reporting do not reasonably reflect the distribution losses NorthWestern is experiencing on its system, BPA will not use the unadjusted loss data reported in NorthWestern's FERC Form 1. *See* BPA Issues List to NorthWestern, Utility-Specific Issues, No. 1 and Section 4.2.1.1.

However, the new distribution loss factor calculation proposal discussed in NorthWestern's May 1, 2013 Comment Letter appears to suggest a methodology which closely approximates the "default method" prescribed in Method 3 of Endnote e the 2008 ASCM, after making certain adjustments to the FERC Form 1 data described above. BPA has reviewed the adjustments NorthWestern proposes to make to its FERC Form 1 data, and agrees that for this ASC Review Period they appear to be reasonable. Moreover, with the new adjustments to NorthWestern's FERC Form 1 data, the resulting distribution loss factor is 5.77 percent, which is reasonable when compared to the distribution loss factors reported by other utilities, and higher than the distribution loss factor BPA proposed to use in NorthWestern's Draft ASC Report. Based on the foregoing, BPA intends to use a distribution loss factor of 5.77% in NorthWestern's ASC calculations for this rate period.

Decision:

For the FY 2014–2015 Appendix 1, BPA will use the 3-year average of NorthWestern's distribution loss factors for the years 2009, 2010, and 2011 (calculated using page 401 FERC Form 1 data adjusted as discussed in detail above), 7.67 percent, reduced by BPA's transmission losses, 1.9 percent, resulting in a Distribution Loss Factor of 5.77 percent. BPA reserves the right to review, evaluate, and make determinations concerning NorthWestern's distribution loss factors in future ASC Review Processes.

4.1.2 Appendix 1 Supporting Worksheets

4.1.2.1 Load Forecast

Issue:

Whether the load attributable to Yellowstone National Park should be included in NorthWestern's Load Forecast.

Parties' Positions:

The Load Forecast contained in NorthWestern's As-Filed FY 2014–2015 ASC Filing contains load attributable to Yellowstone National Park.

BPA Staff's Position:

The load attributable to Yellowstone National Park should be removed from the Load Forecast included in NorthWestern's FY 2014–2015 ASC Filing.

Evaluation of Positions:

In developing the Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act" or "Act"), Congress limited certain features of the Act to utilities and load located within the geographical area defined as the "Pacific Northwest" or "region." *See* 16 U.S.C. § 839a(14)(A)-(B). Specifically, "region" is defined as follows:

> the area consisting of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and
>
> any contiguous areas, not in excess of seventy-five air miles from the area referred to in subparagraph (A), which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region

Id.

Yellowstone National Park is not within the Columbia River drainage basin and, therefore, does not lie within the region.

BPA Staff contends that the backup data to the Load Forecast provided in NorthWestern's Response to Data Request BPA-NW-FY14-01 contains load attributable to Yellowstone National Park. The load attributable to Yellowstone National Park should be removed from the Load Forecast included in NorthWestern's FY 2014–2015 ASC Filing. In response to BPA's Issue List, NorthWestern concurs with the removal of load attributable to Yellowstone National Park from its Load Forecast.

See BPA Issues List to NorthWestern, Utility-Specific Issues, No. 3.

Decision:

NorthWestern's Load Forecast will be revised to exclude the load attributable to Yellowstone National Park.

Table 4.1.2.1-1: Load Forecast Summary Line 21; Total Forecast Energy (MWh)

	FY11	FY12	FY13	FY14	FY15
As-Filed	5,912,124	5,940,411	5,994,804	6,013,493	6,036,667
Adjusted	5,901,610	5,920,565	5,976,341	5,995,030	6,018,204

Table 4.1.2.1-2: Average System Cost (Line 38)

	CY 2011 Total Retail Load (MWh)
As-Filed	5,912,124
Adjusted	5,901,610

4.1.2.2 New Resources – Individual

Issue:

Whether to remove the anticipated reduction in costs and energy due to the energization of the Spion Kop wind project from the New Resources Tab of NorthWestern's Forecast Model.

Parties' Positions:

NorthWestern included an estimate of the reduction in market purchases resulting from the Spion Kop wind project coming on line in the New Resources Tab of its As-Filed FY 2014–2015 ASC Filing.

BPA Staff's Position:

The reduction in market purchases resulting from the Spion Kop wind project coming on line should be removed from the New Resources Tab of NorthWestern's As-Filed FY 2014–2015 ASC Filing.

Evaluation of Positions:

The ASC Forecast Model calculates the reduction in market purchases resulting from New Resource additions using BPA's forecast of market prices. In the New Resources Tab of NorthWestern's As-Filed Appendix 1, reducing market purchases (costs and energy) to offset the increase in generation produced by the Spion Kop wind farm coming on line results in duplicate adjustments of this reduction. In response to BPA's Issue List, NorthWestern concurs that the reduction in market purchases (costs and energy) resulting from the Spion Kop wind project coming on line (cells F76 and F77) should be removed from the Resources tab.

See BPA Issues List to NorthWestern, Utility-Specific Issues, No. 4.

Decision:

BPA will remove the reduction in market purchases (costs and energy) resulting from the Spion Kop wind project coming on line from the New Resources Tab of NorthWestern's As-Filed FY 2014–2015 ASC Filing.

Table 4.1.2.2-1: New Resources – Individual

	Contract Termination ($) (Cell F76)	Contract Termination (MWh) (Cell F77)
As-Filed	(3,450,000)	(138,000)
Adjusted	0	0

4.2 Decisions on Draft Report Unresolved Issues

During the ASC Review Process, BPA Staff raised the "Resolved Issues" discussed in Section 4.1, above, and the "Unresolved Issues" identified below. NorthWestern responded to these issues in its September 21, 2012, Issue List response, and to the NorthWestern Draft ASC Report in two "Comment Letters" dated, respectively, April 9 and May 1, 2013. No other party raised issues with, or commented on, NorthWestern's June 4, 2012, ASC Filing. BPA Staff considers the issues identified in this section resolved.

In its April 9 Comment Letter, NorthWestern requested that they be granted an extension of time, until May 1, 2013, to comment on its unresolved issue. On May 1, 2013, NorthWestern advised that they had prepared a proposed distribution loss factor based on a three-year average of adjusted 2009, 2010, and 2011 FERC Form 1 data. NorthWestern's proposal is more fully discussed below.

4.2.1 Schedule 4 – Average System Cost

4.2.1.1 Alternative Distribution Loss Factor

Issue:

What distribution loss factor should BPA use when none of the methods specified in the 2008 ASCM can be used?

Parties' Positions:

NorthWestern acknowledges that the data reported in its FERC Form 1 does not result in a reasonable distribution loss factor. NorthWestern also acknowledges that it does not have a distribution loss study that is less than seven years old or revenue grade meters. NorthWestern felt that through continued review and discussion with BPA Staff, an appropriate distribution loss factor could be developed.

In its May 1 Comment Letter, NorthWestern advised that they had conducted an in depth review of the data provided on page 401 of the FERC Form 1 that could be used under the 2008 ASCM to calculate distribution loss factors. They then prepared a proposed alternative distribution loss factor calculation by making certain adjustments to the page 401 FERC Form 1 data. In this calculation, they used the Montana only detail on page 401 and then removed the system balancing load and unbilled sales attributable to all of NorthWestern's control area, except what was related to NorthWestern's default supply (native load) customers. They also removed the generation, purchases and sales to consumers in the Yellowstone National Park (YNP), as YNP is not included in the "Region' as defined in the Northwest Power Act. Sales to Ultimate Consumers, which includes unbilled sales (the estimated difference between the cyclical and calendar data) related to choice customers, was also removed. In an effort to approximate the calculation prescribed by the ASCM "Default Method" (*i.e.*, Method 3 in Endnote e), NorthWestern performed this series of calculations for years 2009, 2010, and 2011, and then computed a three-year average to arrive at a distribution loss calculation of 5.77 percent.

NorthWestern believes that this calculation provides a reasonable alternative distribution loss factor.

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

As noted above in Section 4.1.1.1, the loss information NorthWestern reports in its FERC Form 1 does not conform to the requirements of the ASCM. Because the (unadjusted) data NorthWestern reports in its FERC Form 1 does not result in a reasonable distribution loss factor as contemplated by Endnote e, BPA Staff could not use that data to calculate NorthWestern's distribution loss factor. Nevertheless, BPA Staff needs to identify a reasonable distribution loss factor to use in the calculation of NorthWestern's ASC for the FY 2014–2015 period.

In NorthWestern's Draft ASC Report, Staff considered the following two alternatives to obtain a more reasonable distribution loss factor:

- Use the distribution loss factor of 4.66 percent calculated by BPA and agreed to by NorthWestern for the FY 2012–2013 ASC Review Period; or

- Use the Montana Public Service Commission ("MPSC") System Average Loss Factor, 7.47 percent, for NorthWestern's system cited in NorthWestern's "Application for Approval of Interim Rates for Mill Creek Generating Station" filed in Docket D2008.8.95 with the MPSC ("Mill Creek Interim Request") (Page 1, Attachment E, Mill Creek Interim Request), reduced by BPA's transmission losses, 1.9 percent, which results in a Distribution Loss Factor of 5.57 percent.

Since then, however, NorthWestern submitted its May 1 Comment Letter which provided a proposal to use a three-year average (2009-2011) of the distribution losses calculated using adjusted FERC Form 1 data as described above.

<u>Evaluation of Positions:</u>

Initially, BPA Staff considered using the 4.66 percent distribution loss factor approved for use in NorthWestern's FY 2012–2013 Final ASC Report. Staff also researched NorthWestern's recent filings with the MPSC. Although most of these comprised only one year of data, the MPSC Mill Creek Interim Request filings data was recent and produced results which were within the bounds of reasonableness.

In the Draft Report, Staff proposed to use the distribution loss factor data obtained from NorthWestern's Mill Creek Interim Request for the purposes of this FY 2014–2015 ASC Review Period. (*Id.*) Staff reasoned that that this data reflected NorthWestern's representation of the losses it experienced on its system today. Staff calculated the net loss factor to use on Tab 4 of Appendix 1 by subtracting BPA's transmission loss factor of 1.90 percent from MPSC System Average Loss Factor of 7.4685 percent identified in the Mill Creek Interim Request, resulting in a net loss factor of 5.57 percent (rounded up). BPA Staff believed that this estimate was reasonable; that it reflected NorthWestern's actual system use and, when transmission system loses were subtracted, yielded a distribution loss factor that was within the range of other utilities. *See* BPA Issues List to NorthWestern, Utility-Specific Issues, No. 2.

However, NorthWestern's May 1, 2013 Comment Letter offered another proposal for calculating its distribution loss factor. As described in section 4.1.1.1, BPA agrees that with NorthWestern's proposed adjustments to its FERC Form 1 data, a three-year average of FERC Form 1 data can be used to determine NorthWestern's distribution losses for this ASC Review Process.

Decision:

For the FY 2014–2015 Appendix 1, BPA will use the 3-year average of NorthWestern's Distribution Loss Factors for the years 2009, 2010, and 2011 (calculated using page 401 FERC Form 1 data adjusted as discussed in detail above) of 7.67 percent, reduced by BPA's transmission losses of 1.9 percent, resulting in a Distribution Loss Factor of 5.77 percent. BPA reserves the right to review, evaluate, and make determinations concerning NorthWestern's distribution loss factors in future ASC Review Processes.

Table 4.2.1.1-1: Schedule 4 – Average System Cost; Distribution Loss Factor (Cell F41)

	Distribution Loss Factor (%)
As-Filed	3.08
Adjusted	5.77

Table 4.2.1.1-2: Average System Cost; CY 2011 Total Contract System Load (MWh) (Cell D42)

	CY 2011 Total Contract System Load (MWh)
As-Filed	6,094,218
Adjusted	6,242,133

4.3 ASC Forecast Model Errata Corrections

On April 18, 2012, BPA released its latest ASC Forecast Model to be used for the FY 2014-2015 ASC Review Processes. Following that release date and after the June 4 utility submissions, BPA Staff discovered three formula discrepancies in the ASC Forecast Model, as described below. In the utilities' ASC Draft Reports, BPA proposed the following errata corrections to the Forecast Model. No party provided comments.

4.3.1 Purchased Power and Sales for Resale

BPA Staff discovered a formula error in the worksheet that calculates purchased power expense and off-system sales revenue. Specifically, the forecast model was not recognizing the cost of the Base Period Tier 1 purchases from BPA. This error affected the forecast ASCs of Snohomish County PUD and Clark County PUD only. BPA Staff corrected this error and issued an updated ASC Forecast Model on July 18, 2012. *See* Cell E163 of the OSS & PurPWr Forecast (2) Tab of the ASC Forecast Model.

4.3.2 Market Price Forecast

BPA Staff discovered a formula error in the worksheet that calculates the individual utility market purchase price and market sales price. The worksheet was not recognizing the correct Base Period (CY 2011) actual market price in the INPUTS Tab. The error affected the Exchange Period purchased power expense and sales for resale revenues of all participating utilities. BPA Staff corrected the error prior to providing Exchange Period ASCs for the BP-14 Rate Case Initial Proposal. The ASC Forecast Model with the correction was uploaded simultaneously with the Draft ASC Reports and Draft Appendix 1 models. *See* Cell C46 on the INPUTS Tab of the ASC Forecast Model.

4.3.3 Cash Working Capital Calculation

BPA Staff discovered a formula error in how the ASC Forecast Model was forecasting Cash Working Capital. The Model was not removing fuel and purchased power costs from Account 557 prior to forecasting Cash Working Capital. BPA Staff corrected the error prior to providing Exchange Period ASCs for the BP-14 Rate Case Initial Proposal. The ASC Forecast Model with the correction was uploaded simultaneously with the Draft ASC Reports and Draft Appendix 1 models. The correction affected the Exchange Period ASCs of Avista and Idaho Power Company. *See* Row 85 on the Base Data Tab of the ASC Forecast Model.

5 GENERIC ISSUES

5.1 Introduction

In addition to the foregoing issues, which are limited to NorthWestern, BPA raised the following issues that may be generic to all exchanging utilities. Following the publication of the Draft ASC Reports, no Party commented on any of these generic issues.

5.2 Schedule 1A – Cash Working Capital

5.2.1 Account 557 – Other Expenses

Issue:

Whether expenses associated with purchased power or fuel costs that are recorded in Account 557, Other Expenses, should be removed for purposes of calculating Cash Working Capital (Schedule 1A).

Parties' Positions:

Any fuel-related expenses reported in Account 557 should be excluded in the Cash Working Capital calculation.

BPA Staff's Position:

Any expenses associated with purchased power or fuel costs that are recorded in Account 557, Other Expenses, should be removed for the purposes of calculating Cash Working Capital (Schedule 1A).

Evaluation of Positions:

Endnote f of the 2008 Average System Cost Methodology, Final Record of Decision, states that purchased power and fuel costs should be excluded from the Cash Working Capital calculation.

> f/ Cash working capital (CWC) is a ratemaking convention that is not included in the Form 1, but a 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, BPA 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.

18 C.F.R. § 301, End. f.

This issue was discussed, evaluated, and resolved during the February 2 and April 11, 2012 REP workshops. No additional comments were provided following the publication of the Draft ASC Reports. The IOUs and BPA agreed that any expenses associated with purchased power or fuel costs that are recorded in Account 557, Other Expenses, should be removed from the Cash Working Capital (Schedule 1A) calculation.

See BPA Issues List to NorthWestern, Generic Issues, No. 1.

Decision:

Any expenses associated with purchased power or fuel costs that are recorded in Account 557, Other Expenses, will be removed for the purposes of calculating Cash Working Capital (Schedule 1A).

5.3 ASC Forecast Model

5.3.1 Tier 1 Power Purchases from BPA

Issue:

What level of the COUs' Tier 1 purchases is appropriate to include in the Exchange Period ASC calculation?

Parties' Positions:

BPA raised this issue for the first time in the Draft ASC Report. No Party filed comments on this issue following publication of the Draft Report.

BPA Staff's Position:

The ASC Forecast Model should set Tier 1 purchase amounts equal to the lesser of RHWM (based on Slice amounts assuming critical water) or net requirements, plus the COU's Slice share of Federal Columbia River Power System (FCRPS) surplus under average water.

Evaluation of Positions:

Under the 2008 ASCM, the calculation of IOUs' and COUs' ASCs begins with actual historical data from a Base Period, which is then escalated to the midpoint of the Exchange Period (*i.e.*, October 1, 2014) in accordance with the formulas and rules of the ASC Forecast Model. For the FY 2014–2015 ASC Review Process, the Base Period is calendar year 2011. For both COUs and IOUs, long-term power purchases in the Base Period reflect the utilities' actual purchases. For COUs, the Base Period purchases reflect all power purchases the utility received from BPA (including surplus under Slice).

Differences arise between the COUs and IOUs, however, when BPA escalates the long-term power purchases from the Base Period to the Exchange Period in the ASC Forecast Model.

For IOUs, the 2008 ASCM requires that the output from the utility's own generation and the amount of power from long-term and intermediate power purchases remain constant at the Base Period level; thus, if a utility had 100 aMW of power purchases in CY 2011, BPA would assume that, for the rate period, the utility would again have 100 aMW of long-term power purchases annually. If the utility's existing and long-term resources are insufficient to meet the utility's forecast annual rate period load, the ASC Forecast Model makes up the difference by increasing the utility's short-term market purchases. 18 C.F.R. § 301.4(e).

For COUs, the 2008 ASCM requires BPA to calculate ASC by using "the RHWM System Resources as determined in the [TRM] process." 18 C.F.R. § 301.4(g)(1). To implement this language, BPA Staff designed the ASC Forecast Model to update the COUs' PF power purchases for the Exchange Period (*i.e.*, FY 2014–2015) with the RHWM purchases BPA establishes as part of the RHWM process. These RHWM purchases are based on a critical water assumption, and do not include surplus power that Slice customers may otherwise be entitled to during the Exchange Period. The effect of this modeling input is that COUs' ASCs are based on two different long-term power purchase assumptions: (1) a Base Period long-term power purchase amount determined using *actual* purchases (which reflects actual water conditions), and (2) Exchange Period long-term power purchases determined using *critical* water conditions. If the projected purchases under critical water in (2) are less than the long-term purchases under actual water conditions in (1), the ASC Forecast Model projects that the utility is resource-deficient during the Exchange Period and automatically increases the utility's market purchases (at market prices) to make up the difference. This is the case even though the utility's *actual* power deliveries from BPA are likely to be much greater than the critical water assumption used in calculating the utility's RHWM.

BPA Staff contends that using actual-water-based PF power purchases in the Base Period and then critical-water-based PF power purchases in the Exchange Period is logically inconsistent and not the intent of the 2008 ASCM. Had this modeling anomaly been identified earlier, BPA Staff would have revised the ASC Forecast Model to ensure that both the Base Period and Exchange Period calculations of PF power purchases were using consistent methods. Having now identified the anomaly, BPA Staff proposed in the Draft ASC Reports to make the modeling change to the ASC Forecast Model for purposes of calculating the COUs' ASCs. In determining how to remedy the modeling anomaly, BPA Staff examined three alternatives:

> Alternative 1: Set Tier 1 purchase amounts equal to Base Period PF/Tier 1 purchases. This is the same method used for all other long-term purchases of COUs and long-term purchases of IOUs. The water condition of the base year is assumed to occur in the forecast years; the same assumption is used for IOUs.
>
> Alternative 2: Set Tier 1 purchase amounts equal to the lesser of RHWM or net requirements (the firm Slice amounts), plus the COU's Slice share of FCRPS surplus under average water (thereby using the same assumption as in rates: part of BPA's surplus generation is taken by Slice customers). This alternative sets the COU purchase amounts from BPA according to the "RHWM System Resources" established by BPA in its Power Rate Proceeding.

Alternative 3: Set Tier 1 purchase amounts equal to the lesser of the amounts determined in Alternatives 1 and 2, above.

In the Draft ASC Report, BPA Staff recommended that the COUs' ASCs be calculated using Alternative 2. No Party commented on this issue following publication of the Draft Reports. Therefore, BPA will adopt Alternative 2. Alternative 2 will create an "apples-to-apples" comparison between the long-term purchases considered in the Base Period (which includes surplus under *actual* water conditions) and the long-term purchases updated in the Exchange Period (which includes surplus under average water conditions). This this method also adheres to the ASCM's requirement that BPA use the "the RHWM System Resources as determined in the [TRM] process," which would continue to form the primary basis for the long-term projections used in the ASC Forecast Model. Finally, this method meets the intent of the 2008 ASCM with respect to determining the ASCs of COUs by basing a COU's ASC on the best projection of the utility's PF purchases from BPA during the Exchange Period.

Decision:

BPA will use Alternative 2 to determine what level of Tier 1 purchases is appropriate to include in the Exchange Period ASC calculation: Set Tier 1 purchase amounts equal to the lesser of the RHWM or net requirements (the firm Slice amounts), plus the COU's Slice share of FCRPS surplus under average water.

5.3.2 Calculation of ASC Delta for New Resource Additions

Issue:

What is the appropriate method to calculate the ASC delta for new resource additions?

Parties' Positions:

BPA raised this issue for the first time in the Draft ASC Report. No Party filed comments on this issue following publication of the Draft Report.

BPA Staff's Position:

BPA will calculate an ASC delta for each new resource addition, and combination of new resource additions, contained in the utilities' ASC Filings.

Evaluation of Positions:

During the ASC reviews, BPA Staff became aware of an issue regarding the calculation of the ASC delta for new resource additions. PGE is the only utility affected by this issue in the FY 2014–2015 Review Processes, but other utilities may be affected in the future.

For a utility with multiple new resource additions that meet the materiality threshold of 2.5 percent and with an existing NLSL, the ASC delta can differ depending on which new resource (or combination of new resources) has previously come on line. The differing ASC deltas result from the effect of the particular new resource addition, or specific combination of new resource additions, on the $/MWh cost to serve NLSLs. To determine the ASC delta under every scenario, BPA calculated an ASC delta for each new resource, individually, and each possible combination of new resources. In the event a new resource, or specific combination of new resources, comes on line, the corresponding ASC delta is the amount to be added to PGE's Exchange Period ASC which was calculated before the addition of any new resources. The ASC deltas are shown on Table 2.7-1 in PGE's Final ASC Report.

Decision:

For the Final ASC Reports, where applicable, BPA will calculate an ASC delta for each new resource addition, and each combination of new resource additions, contained in the utilities' ASC Filings.

6 FY 2014–2015 ASC

NorthWestern's As-Filed, Base Period (CY 2011) ASC was $68.96/MWh. As a result of adjustments made during the review process, NorthWestern's Base Period ASC decreased to $67.32/MWh.

NorthWestern's As-Filed, Exchange Period ASC for FY 2014–2015 was $69.63/MWh. As a result of adjustments made during the review process, NorthWestern's Exchange Period ASC for FY 2014–2015 increased to $70.65/MWh. These adjustments include new resources, if any, that came on line prior to the Exchange Period.

The proposed Exchange Period ASC does not reflect any changes in NLSL status. Please refer to Section 2.7 for potential NLSL adjustments to Exchange Period ASCs.

7 REVIEW SUMMARY

This Final ASC Report is BPA's determination of NorthWestern's FY 2014 and FY 2015 ASC based on information and data provided by NorthWestern, including comments, if any, received in response to the Draft ASC Report, and based on the professional review, evaluation, and judgment of BPA's REP Staff.

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. The information and analysis contained herein properly establish NorthWestern's ASC for FY 2014–2015.

8 APPROVAL ON BEHALF OF THE BONNEVILLE POWER ADMINISTRATION

I have examined NorthWestern'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 NorthWestern's ASC.

Issued in Portland, Oregon, this 24th day of July, 2013.

BONNEVILLE POWER ADMINISTRATION

By: */s/ Mark. O. Gendron*
Vice-President, Northwest Requirements Marketing

BONNEVILLE POWER ADMINISTRATION

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