

**FY 2020-2021**

**FINAL  
AVERAGE SYSTEM COST REPORT**

Public Utility District No. 1  
of Snohomish County

July 2019





**FY 2020-2021**

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AVERAGE SYSTEM COST REPORT**

**FOR**

**Public Utility District No. 1  
of Snohomish County**

Docket Number: ASC-20-SN-01

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

July 2019

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## TABLE OF CONTENTS

Section	Page
<b>1 FILING DATA .....</b>	<b>1</b>
<b>2 AVERAGE SYSTEM COST SUMMARY .....</b>	<b>5</b>
2.1 Snohomish Background .....	5
2.2 Base Period ASC .....	5
2.3 FY 2020-2021 Distribution Loss Factor .....	6
2.4 FY 2020-2021 Exchange Period ASC .....	6
2.5 ASC Major Resource Additions or Removals .....	7
2.6 NLSL Adjustment .....	10
2.7 NLSL Formula Rate .....	11
<b>3 FILING REQUIREMENTS .....</b>	<b>13</b>
3.1 ASC Review Process – FY 2020-2021 .....	13
3.2 Explanation of Appendix 1 Schedules .....	14
3.2.1 Schedule 1 – Plant Investment/Rate Base .....	14
3.2.2 Schedule 1A – Cash Working Capital .....	15
3.2.3 Schedule 2 – Capital Structure and Rate of Return .....	15
3.2.4 Schedule 3 – Expenses .....	15
3.2.5 Schedule 3A – Taxes .....	15
3.2.6 Schedule 3B – Other Included Items .....	16
3.2.7 Schedule 4 – Average System Cost (\$/MWh) .....	16
3.2.8 Purchased Power and Sales for Resale .....	16
3.2.9 Load Forecast .....	16
3.2.10 Distribution Loss Calculation .....	17
3.2.11 Distribution of Salaries and Wages .....	17
3.2.12 Ratios .....	17
3.2.13 New Resources – Individual and Grouped .....	17
3.2.14 Materiality for New Resource Additions – Individual and Grouped .....	18
3.2.15 New Large Single Loads .....	19
3.2.16 Tiered Rates .....	19
3.2.17 Above-RHWM Base Calculation .....	20
3.3 Rate Period High Water Mark ASC Calculation under the Tiered Rate Methodology .....	20
3.4 ASC Forecast .....	21
3.4.1 Forecast Contract System Cost .....	21
3.4.2 Forecast of Sales for Resale and Power Purchases .....	21
3.4.3 Forecast Contract System Load and Exchange Load .....	22
3.4.4 Load Growth Not Met by New Resource Additions .....	22
<b>4 REVIEW OF THE ASC FILING .....</b>	<b>23</b>
4.1 Errata Corrections Filed by Utility .....	25
4.1.1 Schedule 1 - Rate Base .....	25
4.1.2 Schedule 3 - Worksheet Expenses .....	25
4.1.3 ‘3-Year PP & OSS Worksheet’ tab .....	26
4.1.4 ‘Tiered Rates’ tab .....	26
4.2 Decision on Draft Report Resolved Issues .....	27

4.2.1	Schedule 1 – Rate Base .....	27
4.2.1.1	Account 189 – Unamortized Loss on Reacquired Debt .....	27
4.2.2	‘New Resources – Individual’ tab & ‘Materiality – Individual’ tab .....	30
4.3	Decision on Draft Report Identification and Analysis of Unresolved Issues .....	31
<b>5</b>	<b>GENERIC ISSUES AND STATEMENTS.....</b>	<b>33</b>
<b>6</b>	<b>FY 2020-2021 ASC .....</b>	<b>35</b>
<b>7</b>	<b>REVIEW SUMMARY.....</b>	<b>35</b>
<b>8</b>	<b>APPROVAL ON BEHALF OF THE BONNEVILLE POWER ADMINISTRATION .....</b>	<b>35</b>

**List of Tables**

Table 2.2-1:	CY 2017 Base Period ASC .....	6
Table 2.4-1:	Exchange Period FY 2020-2021 ASC (\$/MWh) With No Major Resource Additions or Removals .....	7
Table 2.5-1:	Major Resources Coming On Line or Being Removed <i>Prior to</i> the Exchange Period (\$/MWh).....	9
Table 2.5-2:	Major Resources Coming On Line or Being Removed <i>During</i> the Exchange Period (\$/MWh).....	9
Table 2.6-1:	New Large Single Loads Under Review .....	10
Table 2.6-2:	New Large Single Loads that Begin Taking Power <i>Prior to</i> the Exchange Period.....	11
Table 2.6-3:	New Large Single Loads that Begin Taking Power <i>During</i> the Exchange Period.....	11
Table 2.7-1:	NLSL Formula Rate Inputs: Contract System Cost and Cost of Serving NLSL.....	12
Table 2.7-2:	Formula Rate Input: Contract System Load.....	12
Table 4-1:	Summary of ASC Errata Corrections and Issues .....	24
Table 4.2.1-1:	Account 189, Unamortized Loss on Reacquired Debt .....	29
Table 4.2.1-2:	Account 186, Miscellaneous Deferred Debits.....	29

## 1 FILING DATA

Utility:           **Public Utility District No. 1 of Snohomish County**  
2320 California Street  
Everett, Washington 98201  
<http://www.snopud.com>

Parties to the Filing:

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

Consumer-Owned Utilities (“COUs”):  
    Clark Public Utilities (“Clark”)

Average System Cost Base Period: Calendar Year (“CY”) 2017

Effective Exchange Period: Fiscal Years 2020-2021, October 1, 2019 – September 30, 2021

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”). Under the REP, any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (“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)(1) and 7(b)(3) of the Act. 16 U.S.C. §§ 839e(b)(1), 839e(b)(3); 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 farm consumers. 16 U.S.C. § 839c(c)(3). A utility participating in the REP will hereinafter be referred to as a “Utility” or “Exchanging Utility.”

The Northwest Power Act grants to BPA’s Administrator the authority to determine Utilities’ average system cost(s) (“ASC”) based on a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). 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<sup>1</sup> 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 Act limits eligibility for the REP 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.*

BPA has conducted an ASC review to determine Snohomish’s ASC for fiscal years (“FY”) 2020–2021 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 2020-2021 Final Average System Cost Report (“Final ASC Report”) describes BPA’s ASC review process and evaluation used to implement 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 (“FERC”) final ruling and the *2008 ASCM*, available at [Federal Energy Regulatory Commission's Final Ruling and the 2008 ASCM](#), and the *Average System Cost Methodology Final Record of Decision (“2008 ASCM ROD”)*, June 30, 2008, available at [BPA’s Residential Exchange Program](#) website.

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<sup>1</sup> A new large single load (NLSL) is defined in section 3(13) of the Northwest Power Act, and determined by BPA as specified in power sales contracts with its Regional Power Sales customers. 16 U.S.C. §§ 839a(13). *See* section 2.6 of this report for more details.

General information regarding the ASC Review Process can be found at [BPA's Residential Exchange Program](#) website.

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

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## 2 AVERAGE SYSTEM COST SUMMARY

### 2.1 Snohomish Background<sup>2</sup>

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

The Everett, Washington-based public utility serves an area of approximately 2,200 square miles and serves over 350,000 electric customers.

Snohomish provides electric service to its customers over 6,496 miles of transmission and distribution lines. It owns generating capacity of 120 megawatts (“MW”). In 2017, BPA supplied approximately 86 percent of Snohomish’s energy; the remainder was supplied by three hydro projects (Jackson, Woods Creek, Youngs Creek), wind/other renewables, and market purchases.

### 2.2 Base Period ASC

The 2008 ASCM requires Utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA “Base Period” financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, or the most recent audited financial statements (Annual Reports) for COUs. The Base Period data are derived from the Base Period FERC Form 1s (for IOUs) or the Annual Reports (for COUs), and underlying accounting system data for all Utilities. For purposes of the FY 2020-2021 filing period, the Base Period is CY 2017. The submitted information includes the “Appendix 1,” an Excel-based workbook populated with financial and load data used to calculate the Base Period ASC.

Table 2.2-1 summarizes the 2017 Base Period ASC based on (1) the information contained in Snohomish’s June 4, 2018 ASC Filing (“As-Filed”), and (2) as adjusted by BPA (including errata corrections filed by Snohomish) in this Final ASC Report. This table does not reflect the Exchange Period (defined below) ASC, which is noted in subsequent tables.

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<sup>2</sup> Information stated in this section was sourced from Snohomish’s website and 2017 Annual Report.

**Table 2.2-1: CY 2017 Base Period ASC**  
(Results of Appendix 1 calculations)

	<b>June 4, 2018</b>	<b>July 25, 2019</b>
	<b>As-Filed</b>	<b>Final ASC Report</b>
Production Cost	\$300,157,683	\$291,367,344
Transmission Cost	\$69,062,981	\$68,996,909
(Less) NLSL Costs	\$0	\$0
(Less) Above-RHWM Costs	\$0	\$0
<b>Contract System Cost (“CSC”)</b>	<b>\$369,220,664</b>	<b>\$360,364,253</b>
Total Retail Load (MWh)	6,594,137	6,594,137
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	6,594,137	6,594,137
Distribution Losses	244,957	244,957
(Less) Above-RHWM Load	0	0
<b>Contract System Load (“CSL”)</b>	<b>6,839,094</b>	<b>6,839,094</b>
<b>CY 2017 Base Period ASC</b> <b>(CSC/CSL)</b>	<b>\$53.99/MWh</b>	<b>\$52.69/MWh</b>

### 2.3 FY 2020-2021 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.

Losses are the distribution energy losses occurring between the transmission portion of the Utility’s system and the meters measuring firm energy load. *Id.* The distribution loss can be measured using one of the three 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 a comparable data source. *Id.*

BPA Staff reviewed and accepted Snohomish’s supporting Distribution Loss Factor calculations. For purposes of this Draft ASC Report, BPA will use the Distribution Loss Factor of 3.71 percent included in Snohomish’s As-Filed Appendix 1.

### 2.4 FY 2020-2021 Exchange Period ASC

BPA and intervenors had the opportunity to review, evaluate, and comment on each Utility’s Appendix 1 historical costs and forecast loads submitted in the ASC Review Process. Once the Base Period ASC was determined, the cost data were escalated forward using the “ASC Forecast Model,” an Excel-based macro model, to the midpoint of the Exchange Period, which in this instance is October 1, 2020. For purposes of the FY 2020-2021 ASC Review Period, the Exchange Period is October 1, 2019, through September 30, 2021 (“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, such as updates to BPA’s natural gas and market price forecasts, errata corrections, or other changes made by BPA. For all Utilities, BPA updated natural gas and market price forecasts to match natural gas and market price forecasts in the Final Proposal for the BP-20 Rate Proceeding. See the “Input” tab of the ASC Forecast Model for the Utility’s (1) As-Filed and (2) BPA-Adjusted models for additional details.

Although Snohomish’s Base Period ASC remains unchanged, its Exchange Period ASC increased from the Draft ASC Report due to higher natural gas and market prices. In October 2018, a portion of the Enbridge natural gas pipeline ruptured in British Columbia, Canada. The ensuing outage, repairs, and inspections reduced import capacity from Canada to the Pacific NW at Sumas throughout the winter, and will likely continue to do so through this summer. This restriction, in addition to the strong winter demand, escalated the natural gas price throughout the region and increased the natural gas price used to calculate the FY 2020-2021 ASCs from 2.004 \$/MMBtu (Draft ASC Reports) to 5.234 \$/MMBtu (Final ASC Reports).

All other adjustments, if any, made during the review are explained in section 4 of this Final ASC Report.

For the COUs only, BPA updated Rate Period High Water Marks (“RHWMs”) in the ‘Tiered Rates’ tab in the Appendix 1, and the rates in the ‘PF-Rates’ tab of the Forecast Model to match what is being used in the BP-20 Final Proposal. In the ‘Tiered Rates’ tab of the Forecast Model, BPA calculated the total cost of power purchased from BPA.

Table 2.4-1 identifies the Exchange Period ASC the Utility filed on June 4, 2018, and as adjusted by BPA (including errata corrections filed by Snohomish) 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 and discussed in section 2.5 of this Final ASC Report, or the Utility is subject to a New Large Single Load (“NLSL”) adjustment as discussed in section 2.6.

**Table 2.4-1: Exchange Period FY 2020-2021 ASC (\$/MWh)  
With No Major Resource Additions or Removals**

<b>Date</b>	<b>June 4, 2018 As-Filed</b>	<b>July 25, 2019 Final ASC Report</b>
FY 2020-2021	60.45	54.68

## **2.5 ASC Major Resource Additions or Removals**

Under the 2008 ASCM, a Utility’s ASC may be adjusted to reflect the addition or loss of a major 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 or existing resource must be used to meet a Utility’s retail load during the Exchange Period.

For ASC calculation purposes, a major resource adjustment may be included in an IOU's ASC at the commencement of the Exchange Period if such resource becomes commercially operational (or ceases production) after the Base Period, but before the Exchange Period begins. For COUs only, a major resource adjustment may be included in a COU's ASC at the commencement of or during the Exchange Period.

Before a Utility's ASC is adjusted to reflect the addition or loss of a major 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 a resource that affects a Utility's Base Period ASC by two and one-half percent (2.5%) or more will be considered a major resource. 18 C.F.R. § 301.4(c)(4). This is the materiality threshold. The 2008 ASCM also 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 one-half percent (0.5%) or more. *Id.* See also section 3.2.14 of this Final ASC Report.

In order for major resource additions to be included in Snohomish's Exchange Period ASC at the beginning of the Exchange Period, a Major Resource Attestation must be received by BPA no later than the tenth (10th) business day after the Exchange Period begins.

Table 2.5-1 summarizes the major resource additions, prior to any NLSL adjustments, that are projected to become commercially operational, and major resources that will cease to be commercially operational, prior to the beginning of the Exchange Period (*i.e.*, January 1, 2018 - September 30, 2019).

Snohomish included several new resources in its ASC Filing, of which three came online in early 2018, prior to the Exchange Period. The three new resources are: Calligan, Hancock (both hydroelectric generating projects), and a New PTP 100 MW transmission contract. In addition, Snohomish grouped these resources with its other resources (of which some are slated to come online during the Exchange Period), included in the Appendix 1, New Resource – Individual tab, in order to meet the 2.5% materiality threshold required to qualify as a major resource.

After a thorough review, BPA determined that only Calligan and Hancock met the individual materiality of 0.5% to submit as a stack; however, the aggregate materiality of these two resources did not meet the 2.5% threshold required to qualify as a major resource. Therefore, BPA did not include any of the resources submitted by Snohomish in the determination of its Exchange Period ASC.

**Table 2.5-1: Major Resources Coming On Line or Being Removed  
Prior to the Exchange Period (\$/MWh)**

<b>As-Filed FY 2020-2021 Exchange Period ASC</b>				
<b>Resource</b>	<b>N/A</b>	<b>N/A</b>	<b>N/A</b>	<b>N/A</b>
Expected On Line or Removal Date				
<b>Final ASC Report FY 2020-2021 Exchange Period ASC</b>				
<b>Resource</b>	<b>N/A</b>	<b>N/A</b>	<b>N/A</b>	<b>N/A</b>
Expected On Line or Removal Date				

For COUs only, resources that commence commercial operations during the Exchange Period are reflected in the ASC following receipt by BPA of the Utility’s Major Resource Attestation. Table 2.5-2 summarizes the major resource additions, prior to any NLSL adjustments, that are projected to become commercially operational, and the major resources that will cease to be commercially operational *during* the Exchange Period.

Snohomish included new resources in its ASC Filing, which were slated to come online during the Exchange Period. These resources did not meet the materiality requirements for a major resource and were not included in the determination of Snohomish’s Exchange Period ASC.

**Table 2.5-2: Major Resources Coming On Line or Being Removed  
During the Exchange Period (\$/MWh)**

<b>As-Filed FY 2020-2021 Exchange Period ASC</b>				
<b>Resource</b>	<b>N/A</b>	<b>N/A</b>	<b>N/A</b>	<b>N/A</b>
Expected On Line or Removal Date				
Delta*				

<b>Final ASC Report 2020-2021 Exchange Period ASC</b>				
<b>Resource</b>	<b>N/A</b>	<b>N/A</b>	<b>N/A</b>	<b>N/A</b>
Expected On Line or Removal Date				
Delta*				

\*The Delta is the incremental change in the ASC as the major resources come on line or are removed.

Although the 2008 ASCM permits a Utility’s ASC to be adjusted to reflect the inclusion of a major new resource that comes on-line during the Exchange Period, as part of the 2012 Residential Exchange Program Settlement Agreement, BPA Contract No. 11PB-12322

(“2012 REP Settlement”), all six regional IOUs 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. As a result of this waiver, the ASC reports do not include major resource additions that are scheduled to come on line during the Exchange Period for any IOU.<sup>3</sup>

## 2.6 NLSL Adjustment

An 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 a consecutive 12-month period. 16 U.S.C. § 839a(13)(A)-(B).

By law, NLSLs and 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). In addition, the ASCM does not permit a Utility’s ASC to increase as a result of excluding the cost of resources used to serve NLSLs. *See* 2008 ASC Methodology, Final Record of Decision, at 93. In such cases, BPA will not remove a Utility’s NLSL and associated costs. 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 2.7 of this Final ASC Report.

NLSLs are not determined in the ASC Review Process. 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.

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

**Table 2.6-1: New Large Single Loads Under Review**

<b>As-Filed FY 2020-2021 NLSL Load Amount (MWh)</b>	
<b>NLSL(s)</b>	<b>Load</b>
N/A	N/A

  

<b>Final ASC Report FY 2020-2021 NLSL Load Amount (MWh)</b>	
<b>NLSL(s)</b>	<b>Load</b>
N/A	N/A

<sup>3</sup> The exchanging COUs did not make such a waiver and will continue to include major new resource additions during the Exchange Period under the rules of the 2008 ASCM.

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

<b>As-Filed FY 2020-2021 Exchange Period ASC (MWh)</b>				
<b>Customer</b>	N/A	N/A	N/A	N/A
Expected Start Date				
<b>Final ASC Report FY 2020-2021 Exchange Period ASC (MWh)</b>				
<b>Customer</b>	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**

<b>As-Filed FY 2020-2021 Exchange Period ASC (MWh)</b>				
<b>Customer</b>	N/A	N/A	N/A	N/A
Expected Start Date				
<b>Final ASC Report FY 2020-2021 Exchange Period ASC (MWh)</b>				
<b>Customer</b>	N/A	N/A	N/A	N/A
Expected Start Date				

**2.7 NLSL Formula Rate**

Beginning with the FY 2014–2015 Exchange Period, BPA and Utilities agreed to use a formula rate calculation to remove resource costs from a Utility’s ASC when an NLSL occurs after the Base Period. The reason was to alleviate additional administrative and calculation issues surrounding NLSLs taking power during an Exchange Period.

Base Period NLSLs will remain constant throughout the duration of the Exchange Period (*see* FY 2012-2013 Final ASC Report, section 5.2.2).

For purposes of this Draft ASC Report, no Utility identified potential new NLSLs taking power prior to or during the FY 2020–2021 Exchange Period. 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:

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

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.

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

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

<b>Inputs for both <i>Prior to</i> and <i>During</i> the Exchange Period</b>			
	<b>Timing of New Resource</b>	<b>Contract System Cost (\$)</b>	<b>Cost of Serving NLSL (\$/MWh)</b>
<i>None</i>	N/A	N/A	N/A
<i>Prior to</i>	N/A	N/A	N/A
<i>During</i>	N/A <sup>4</sup>	N/A	N/A

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

<b>FY 2020-2021 Contract System Load (MWh)</b>
N/A

<sup>4</sup> Under the 2012 REP Settlement Agreement, IOUs no longer include new resource additions during the Exchange Period. COUs will continue to include new resource additions during the Exchange Period under the rules of the 2008 ASCM.

### 3 FILING REQUIREMENTS

#### 3.1 ASC Review Process – FY 2020-2021

Utilities' ASCs are established in BPA's ASC Review Processes. The ASC Review Processes for FY 2020-2021 began on June 4, 2018, with the submittal of ASC Filings by the following eight Utilities: Avista, Clark, Idaho Power, NorthWestern, PacifiCorp, Portland General, Puget, and Snohomish.

Notice of the ASC Review Processes was provided on BPA's REP public website, BPA's Secure REP website and via email. The Utilities posted ASC Filings on BPA's Secure REP website by the June 4, 2018, filing deadline. BPA released the FY 2020-2021 ASC Forecast Model in late June, 2018; the model included updated data to be consistent with the BP-20 Rate Proceeding (see section 3.4). Each Utility was then required to run the Forecast Model with its associated As-Filed Appendix 1 to develop its As Filed Exchange Period ASC. Snohomish posted its ASC Forecast Model to the Secure REP website on July 3, 2018.

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 the opportunity to request data, submit comments, and raise issues with the Utilities' ASCs throughout a three-month discovery period; the filing Utilities, in turn, were afforded the opportunity to respond to requests for data, raise and respond to issues, and answer any questions relative to the ASC Filings. BPA engaged in the discovery process throughout the entire ASC Review Process.

Draft ASC Reports were issued January 14, 2019, for each of the eight Utilities. The schedule afforded parties with an approximately three-month period (through April 17, 2019) in which to submit comments to the Draft ASC Reports. See sections 4 and 5 to review comments, if any, submitted by the Utilities and intervenors. Additionally, BPA offered to hold both a clarification workshop and oral argument if requested by any party. BPA did not receive any requests, and as a result, neither event was held.

This Final ASC Report reflects BPA's findings following its initial review of Snohomish's ASC Filing and addresses the errata, issues and questions, if any, raised by the Utility, intervenors, and/or BPA during the ASC Review Process.

For details of the ASC Review Period and guidelines, please see the Rules of Procedure available at [BPA's Residential Exchange Program](#) website.

Final ASC Reports for each Utility are available at <https://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/FY-20-21-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 for New Resource Additions – Individual and Grouped
15. New Large Single Loads (“NLSL Base New-Calc”)
16. Tiered Rates
17. Above-RHWM Base Calculation

#### **3.2.1 Schedule 1 – Plant Investment/Rate Base**

Schedule 1 of the Appendix 1 establishes the Utility's “Rate Base”, which is the value of property on which the Utility is permitted to earn a specific rate of return (calculated in Schedule 2), in accordance with rules set by the state's Public Utility Commission or other regulatory agency. 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 FERC's 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.<sup>5</sup>

Cash Working Capital is a ratemaking convention that is not included in FERC’s Uniform System of Accounts, but is 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 (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 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 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 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.

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<sup>5</sup> James C. Bonbright *et al.*, *Principles of Public Utility Rates* 244 (2d ed. 1988).

Federal income taxes are included in ASC and are calculated, as applicable, in Schedule 2 – Capital Structure and Rate of Return. For this FY 2020-2021 ASC Review Process, BPA continued to use the Federal Income Tax factor of 35 percent which was current during the CY 2017 Base Period.

### **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).

#### 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 distribution costs or the cost of serving a Utility’s NLSLs. CSC is the numerator in the ASC calculation.

#### Contract System Load (MWh)

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 are the statistical classification codes for all transactions. See 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 IOU is required to provide a four-fiscal-year forecast of its total retail load beginning October 1 of the Base Year, as measured at the meter. For COUs, the total retail loads for this time period are forecast by BPA with the net requirements being computed consistent with the Tiered Rate Methodology (“TRM”). See the Tiered Rates tab in the Appendix 1.

Additionally, each COU is required to provide a four-fiscal-year forecast of its qualifying residential and farm retail load, as measured at the retail meter. However, due to the 2012 REP

Settlement Agreement, the IOUs are no longer required to submit residential and farm load forecasts.

The total retail load forecasts for all Utilities, and residential and farm load forecasts for the COUs, are adjusted for distribution losses. In addition, the total retail load forecasts are adjusted for any NLSLs. 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 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 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 Ratios 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 detailed salary and wage 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 resource, when adding or removing the resource results in a change of the Utility's Base Period ASC of two and one-half percent (2.5%) (the materiality threshold) or more. 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). For major resource reductions, the change to ASC will become effective when the resource is sold, retired, or transferred. 18 C.F.R. § 301.4(c)(2)

See section 2.5 for a discussion of ASC Major Resource Additions or Removals.

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

removed, at the midpoint of the Exchange Period. Under the REP Settlement, IOUs no longer include major resource additions that come on line during the Exchange Period. *See* section 2.5.

Each resource that satisfies the minimum materiality threshold of one-half percent (0.5%) may be entered individually in the “New Resources – Individual” tab. Resources that do not meet the two and one-half percent (2.5%) materiality requirement independently may be grouped together with other resources within “New Resources – Grouped” tab to meet the two and one-half percent (2.5%) 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 for New Resource Additions – 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 new resources that individually result in a change in a Utility’s Base Period ASC of one-half percent (0.5%) or more to meet the two and one-half percent (2.5%) 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’s ASC is changed as a result of a new resource addition.

BPA made materiality determinations for all new resources, if any, submitted by each Utility. To make these determinations, BPA followed the instructions below:

- The Utility must have included the costs and operating characteristics for each new resource addition.
- The Utility must have submitted the resource additions (individual and/or grouped) that met the materiality test(s) given the Utility’s Base Period costs.
- BPA reviewed each new resource addition submitted by the Utility to determine the adequacy of costs and operating characteristics.
- For the Draft ASC Report, BPA calculated the materiality of a Utility’s resources using the Utility’s adjusted Base Period ASC and forecast natural gas prices used in BPA’s

Rate Case Initial Proposal. BPA removed all resources and/or groups of resource additions that did not meet the materiality test(s).

- BPA did not unilaterally regroup resources.
- The Initial Proposal’s natural gas price forecast was the basis for the natural gas fuel costs used to calculate the materiality for new resource additions in both the Draft and Final ASC Reports.
- The Utility had the option to recommend a “regrouping” of resource additions that met the materiality test(s).
- Utilities must have submitted the regrouped resource additions in their comments on the Draft ASC Report.
- Only resources that were reviewed by BPA and participants could be used in the regrouping process.

The final grouping of new resources, if any, was determined after considering the filing Utilities’ and other parties’ comments on the Draft ASC Report based on the foregoing instructions.

The materiality determinations provided in this Final ASC Report are based on the Utility’s Base Period ASC and reflect the natural gas price forecast from the BP-20 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 a 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 CF/CT prior to September 1, 1979, and which will result in an increase in power requirements of ten (10) aMW or more in a 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. Base Period NLSLs will remain constant throughout the duration of the Exchange Period (*see* FY 2012-2013 Final ASC Report, section 5.2.2).

### **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 to not include in its ASC the cost of resources necessary to serve the COU’s Above-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 Final 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. For background information and details, see <http://www.bpa.gov/news/pubs/PastRecordsofDecision/2009/TRM-12S-A-02.pdf>.

### 3.2.17 Above-RHWM Base Calculation

The Above-RHWM Base Calc tab calculates the cost of resources in an amount sufficient to serve a COU's Above-RHWM load. Under the TRM and CHWM Contracts, BPA must exclude from a Utility's ASC any Above-RHWM load and an amount of resource costs sufficient to serve such Above-RHWM load. To determine the amount of resource costs to exclude from a Utility's ASC, BPA follows the methodology described in Exhibit D of the Utility's CHWM Contract.

The associated Above-RHWM Ratios tab calculates the functionalization ratios used to allocate the total amount of materials and supplies cost, general plant and general plant depreciation expense, administrative and general costs, Federal and state employment taxes, and property taxes that are to be included in the total costs of resources used to meet a Utility's Above-RHWM load.

### 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.

- $$\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$$
- NewRes\$ is the forecast cost of resources used to serve a customer's Above-RHWM Load. The costs included in NewRes\$ will be determined using a methodology similar to Appendix 1, Endnote d, of BPA's 2008 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 RHWM ASC:

- Power purchases less than five years in 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.
- $\text{NewRes\$} = \text{NewResMWh} \times \text{Fully Allocated Cost}$  (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.

### 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 IHS Global Insight’s (an international economic and market forecasting company) forecast of cost increases for capital costs and fuel (except natural gas), operations and maintenance (“O&M”), and general and administrative (“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 rate 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-18 rate proceeding. 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 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).

#### 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 part of its ASC Filing, each IOU is required to provide a four-fiscal-year forecast of its total retail load, as measured at the meter. For the COUs only, the total retail forecast loads, as determined by BPA under the TRM, will be provided through the end of the Exchange Period. In addition, for the COUs, qualifying residential and farm retail loads, as measured at the retail meter, are required. The IOUs' qualifying residential and farm retail loads are determined in a separate process as described in the 2012 REP Settlement.

Each Utility is required to submit a current distribution loss study as described 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 began the FY 2020-2021 ASC Review Process of Snohomish's ASC Filing in June 2018. BPA raised two issues related to Snohomish's ASC Filing as identified in BPA's Issue List for FY 2020-2021 ASC Filing: Snohomish County PUD ("Issue List"); no other party raised issues. Snohomish responded to each issue, and also submitted separate errata corrections.

This Final ASC Report summarizes BPA's review of Snohomish's ASC Filing and any comments received during the Draft ASC Report comment period.

BPA's ASC determinations for all Utilities are limited to specific findings on issues identified for comment, with the exception of ministerial or mathematical errors or deviations due to changes in functionalizations. There may be additional issues 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 as to the proper interpretation to be applied either in subsequent ASC 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.

On April 11, 2018, prior to the start of the FY 2020–2021 ASC Review Processes, BPA held a conference call/workshop with parties interested in the ASC Review Processes to review the schedule, rules of procedure, errata corrections, and past generic issues; explain the latest revisions to the Forecast Model; remind Utilities on general accounting and functionalization guidelines for the Appendix 1; and provide time to discuss other REP topics of interest from the workshop participants.

In addition to the discussions stated above, BPA requested input on how the utilities are recording the treatment of costs and revenues from the EIM (Energy Imbalance Market), and provided clarification on the changes in the marginal federal income tax rate. In regards to the tax issue, for this ASC filing, BPA will continue to use the 35 percent marginal tax rate as reported in the CY 2017 Base Period. The parties and BPA resolved all questions and were satisfied with the outcome. No further public discussions took place.

Table 4-1 summarizes any direct adjustments BPA made to Snohomish's Appendix 1 in this Final ASC Report as a result of BPA's review and evaluation. Supporting arguments may be found in the Errata, Resolved Issues and/or Unresolved Issues sections listed in Table 4-1.

Although a Utility's state, county, or municipal regulatory bodies, or the Commission, may allow a particular functionalization to a specific account, BPA is not required to follow that treatment when calculating ASCs under the 2008 ASCM. Rather, BPA is tasked with making an independent determination of the appropriateness of inclusion or exclusion of particular costs, the reasonableness of the costs included in Contract System Costs, the appropriateness of

Contract System Loads, and the functionalization method used in the calculation of any cost in conformance with the 2008 ASCM. See Rules of Procedure, § 3.2.2.

**Table 4-1: Summary of ASC Errata Corrections and Issues**

<b>Appendix 1 Schedule</b>	<b>Adjustment</b>
<b>Schedule 1 – Plant Investment/Rate Base</b>	Errata Corrections: section 4.1.1 Direct Adjustment: section 4.2.1.1
<b>Schedule 1A – Cash Working Capital</b>	No direct adjustments.
<b>Schedule 2 – Capital Structure and Rate of Return</b>	No direct adjustments.
<b>Schedule 3 – Expenses</b>	Errata Correction: section 4.1.2
<b>Schedule 3A – Taxes</b>	No direct adjustments.
<b>Schedule 3B – Other Included Items</b>	No direct adjustments.
<b>Schedule 4 – Average System Cost</b>	No direct adjustments.
<b>Appendix 1 Supporting Worksheets</b>	<b>Adjustment</b>
<b>3-Year PP &amp; OSS</b>	Errata Correction: section 4.1.3
<b>Forecast Loads</b>	No direct adjustments.
<b>New Resource Additions – Individual</b>	Direct Adjustment: section 4.2.2
<b>Materiality – Individual</b>	No direct adjustments.
<b>Materiality - Grouped</b>	No direct adjustments.
<b>NLSL Calculation</b>	No direct adjustments.
<b>Wind Resources</b>	No direct adjustments.
<b>Tiered Rates</b>	Errata Correction: section 4.1.4 Updated with data from the BP-20 Final Proposal
<b>Salary and Wages</b>	No direct adjustments.
<b>Ratios</b>	No direct adjustments.
<b>ASC Forecast Model</b>	<b>Adjustment</b>
<b>Natural Gas Updates</b>	Nat_Gas_Mkt_Prices_Tab
<b>Market Price Updates</b>	Nat_Gas_Mkt_Prices_Tab

## 4.1 Errata Corrections Filed by Utility

Snohomish and BPA agreed to the following errata corrections. These corrections were submitted by Snohomish to BPA's Secure REP website on June 26, 2018. *BPA restructured and modified the errata corrections for clarity only; there is no impact to the content.*

### 4.1.1 Schedule 1 - Rate Base

#### Errata Corrections:

**1. Cell H97:**

Deleted formula: ='Direct Analysis'!L12

Inserted formula: =IF(\$E97="DIRECT",\$L97,VLOOKUP(\$E97,Ratio,2,FALSE)\*\$G97)

**2. Cell L97:**

Inserted formula: ='Direct Analysis'!L12

**3. Cell J97:**

Deleted formula: ='Direct Analysis'!L13

Inserted formula: =IF(\$E97="DIRECT",\$N97,VLOOKUP(\$E97,Ratio,4,FALSE)\*\$G97)

**4. Cell N97:**

Inserted formula: ='Direct Analysis'!L13

### 4.1.2 Schedule 3 - Worksheet Expenses

#### Errata Corrections:

**1. Cell H33:**

Deleted formula: ='Direct Analysis'!E159

Inserted formula: =IF(\$E33="DIRECT",\$L33,VLOOKUP(\$E33,Ratio,2,FALSE)\*\$G33)

**2. Cell L33:**

Insert the formula: ='Direct Analysis'!E160

**3. Cell J33:**

Delete formula: ='Direct Analysis'!E160

Inserted formula: =IF(\$E33="DIRECT",\$N33,VLOOKUP(\$E33,Ratio,4,FALSE)\*\$G33)

**4. Cell N33:**

Inserted the formula: ='Direct Analysis'!E161

### 4.1.3 '3-Year PP & OSS Worksheet' tab

#### Errata Corrections:

In its Errata No. 1, Snohomish provided a corrected value for its long-term power purchases recorded in cell D12. Subsequently, through discovery, Snohomish corrected the value again, removing \$260,898 of short-term purchases inadvertently recorded in cell D12, and as a result, moving these short-term purchases to cell D14. Below are both corrections. The first one is from Snohomish's Errata No. 1. The second, and final, correction is from Data Response BPA-SN-FY20-11 (submitted August 27, 2018).

**1. Cell D12:**

Deleted formula: ='Operating GL'!D479+'Operating GL'!D481+'Operating GL'!D482+'Operating GL'!D483+'Operating GL'!D484+'Operating GL'!D491+'Operating GL'!D492+'Operating GL'!D493+'Operating GL'!D494+'Operating GL'!D495+'Operating GL'!D496

Inserted formula: ='Operating GL'!D479+'Operating GL'!D481+'Operating GL'!D482+'Operating GL'!D483+'Operating GL'!D484+'Operating GL'!D491+'Operating GL'!D492+'Operating GL'!D493+'Operating GL'!D494+'Operating GL'!D495+'Operating GL'!D496+'Operating GL'!D485

**2. Cell D12:**

Deleted formula: ='Operating GL'!D479+'Operating GL'!D481+'Operating GL'!D482+'Operating GL'!D483+'Operating GL'!D484+'Operating GL'!D491+'Operating GL'!D492+'Operating GL'!D493+'Operating GL'!D494+'Operating GL'!D495+'Operating GL'!D496+'Operating GL'!D485

Inserted formula: ='Operating GL'!D479+'Operating GL'!D481+'Operating GL'!D482+'Operating GL'!D483+'Operating GL'!D491+'Operating GL'!D492+'Operating GL'!D493+'Operating GL'!D494+'Operating GL'!D495+'Operating GL'!D496+'Operating GL'!D485

**Cell D14:**

Deleted formula: ='Operating GL'!D480

Inserted formula: ='Operating GL'!D480+'Operating GL'!D484

### 4.1.4 'Tiered Rates' tab

#### Errata Corrections:

**1. Cell H7:**

Insert the value: 2,405

**2. Cell I7:**

Insert the value: 2,387

## **4.2 Decision on Draft Report Resolved Issues**

During the ASC Review Process, BPA raised the issues discussed in this section. Snohomish responded to these issues in its Issue List, submitted on September 19, 2018. Following the issuance of the Draft ASC Report, Snohomish submitted a comment letter to the Secure REP website on April 17, 2019, notifying BPA that it “concur and does not have comments.” No other party raised issues or commented on Snohomish’s ASC Filing. BPA considers the issues identified in this section resolved.

### **4.2.1 Schedule 1 – Rate Base**

#### **4.2.1.1 Account 189 – Unamortized Loss on Reacquired Debt**

##### **Issue:**

*Whether Line Item “DefOutflow Pen NPL” is correctly recorded in Account 189 and properly functionalized to PTD.*

##### **Parties’ Positions:**

In its FY 2020-2021 Appendix 1, supporting documentation tab ‘FERC GL,’ Snohomish included Line Item “DefOutflow Pen NPL” for \$12,151,691.38 in the totals for Account 189, Unamortized Loss on Reacquired Debt. Debits and credits included in Account 189 are functionalized using the PTDG ratio.

##### **BPA’s Position:**

Line items ‘288002 Reg Liab – Excess Def Inc Taxes – ID,’ ‘288003 Reg Liab – Excess Deferred Inc Taxes –OR,’ and ‘288005 Reg Liab – Excess Def Inc Taxes – WA’ should be functionalized to DIST.

##### **Evaluation of Positions:**

In its response to Data Request BPA-SN-FY20-12, Snohomish provided additional details on these costs, which are hereafter referred to as Net Pension Liability. Specifically, Snohomish stated:

The “Def Outflow PEN NPL,” is one of the accounts used by the District to book the changes in the Net Pension Liability that does not flow through pension expense. This account was created to conform to GASB No. 68, “Accounting and Financial Reporting for Pensions.” GASB No. 68 states, “Changes in the net pension liability not included in pension expense are required to be reported as deferred outflows of resources or deferred inflows of resources related to pensions. The Deferred Outflow PEN NPL account is composed of the following as of December 31, 2017:

Subsequent contributions:	6,826
Differences between expected and actual experience:	3,773
Changes of assumptions:	396
Changes in proportion and differences between contributions and proportionate share of contributions:	1,156
Total	<u>12,151</u>

Based on Snohomish’s description, the Net Pension Liability account is similar to that of pension deferral accounts that IOUs record in Account 182.3 (Regulatory Assets) and Account 254 (Regulatory Liabilities). The treatment prescribed by the ASCM regarding debits and credits recorded in Accounts 182.3 and 254 is to functionalize them to Distribution until the appropriate public utility commission(s) (PUC) includes such costs in retail rates. Once the debits and credits are approved for inclusion in retail rates, they may be included in the Utility’s ASC. This treatment ensures that the regulatory assets and liabilities recorded in the IOU’s Appendix 1 for ASC purposes generally reflect the costs in the IOU’s retail rates.

Bonneville discussed the importance of connecting regulatory assets and liabilities to costs and credits included in retail rates in the ASCM ROD:

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

ASCM ROD at 149.

Here, Snohomish’s Net Pension Liability resembles the same type of debit or credit that an IOU would record as a regulatory asset (Account 182.3) or regulatory liability (Account 254). This item appears in Snohomish’s Appendix 1 (like a regulatory asset in an IOUs’ FERC Form 1), but does not actually impact retail rates. Snohomish confirmed that its Net Pension Liability is not recovered in its retail rates in its response to Data Request BPA-SN-FY20-12: “This particular account would not have a direct impact on the District’s rates.” The correct ASCM treatment of this cost, then, is to include it in Account 182.3, and functionalize it to Distribution. This treatment does not preclude Snohomish from including these costs in its ASC at the appropriate time. If and when such costs are included as a pension expense in Schedule 3 - Expenses, Snohomish’s ASC will reflect these costs.

Bonneville recognizes that Snohomish is not subject to PUC rulings for its rates, and therefore, it may not record regulatory assets and liabilities in the same manner as an IOU. Nevertheless, Snohomish must still record its debit and credits in a manner that reconciles with the FERC system of accounting. The ASCM recognizes that COUs (like Snohomish) may have different

accounting than that required by the FERC Form 1. In such cases, the COU is required to reconcile its accounts with that of the FERC Form 1. As noted in the ASCM:

18 C.F.R . § 301.7 (c) & (d), Appendix 1 instructions:

(c) The primary source of data for the Investor-owned Utilities' Appendix 1 filings is the Utility's prior year FERC Form 1 filings with the Commission. Any items not applicable to the Utility must be identified.

(d) For Consumer-owned Utilities that do not follow the Commission's Uniform System of Accounts, filings must include reconciliation between Utility Accounts and the items allowed as Contract System Cost.

The above ASCM treatment Bonneville proposes more properly reconciles Snohomish's Net Pension Liability with the items allowed in Contract System Cost.

In response to BPA's Issue List, Snohomish agreed with BPA's recommended account and functionalization adjustments.

**Final Decision:**

*BPA will move line item 'DefOutflow Pen NPL,' for \$12,151,691.38 from Account 189 – Unamortized Loss on Reacquired Debt to Account 186 – Miscellaneous Deferred Debits, and functionalize it to DIST.*

**Table 4.2.1-1: Account 189, Unamortized Loss on Reacquired Debt**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	\$25,207,246	\$3,799,733	\$2,537,932	\$18,869,580
Adjusted	\$13,055,554	\$1,967,991	\$1,314,468	\$9,773,096

**Table 4.2.1-2: Account 186, Miscellaneous Deferred Debits**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	\$66,321,285	\$1,353,160	\$0	\$64,968,125
Adjusted	\$78,472,976	\$1,353,160	\$0	\$77,119,817

#### 4.2.2 ‘New Resources – Individual’ tab & ‘Materiality – Individual’ tab

##### **Issue:**

*Whether the “Supplemental Spill Surcharge” item qualifies as a New Resource and meets the individual materiality to be grouped with other New Resources.*

##### **Parties’ Positions:**

In its FY 2020-2021 Appendix 1, New Resource – Individual tab, Snohomish included the item “Supplemental Spill Surcharge” as a new resource.

##### **BPA’s Position:**

The item “Supplemental Spill Surcharge” does not meet the criteria to qualify as a New Resource, nor does it meet the individual materiality threshold of 0.5 percent to group with Snohomish’s other resources.

##### **Evaluation of Positions:**

In Data Request BPA-SN-FY20-06, BPA noted that this item does not meet any of the criteria for consideration as a major resource addition per ASCM section 18 CFR § 301.4(c)(3):

- (3) A major resource addition or reduction must be related to one or more of the following categories to be eligible for consideration as a major resource:
- (i) Production or generating resource investments;
  - (ii) Transmission investments;
  - (iii) Long-term generating contracts;
  - (iv) Pollution control and environmental compliance investments relating to generating resources;
  - (v) Long-term transmission contracts;
  - (vi) Hydroelectric relicensing costs and fees; and
  - (vii) Plant rehabilitation investments.

In addition, BPA stated, “that it does not meet the 0.5% individual materiality for grouping,” per section 18 CFR § 301.4, (c)(4):

- (4) 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.

In its response, Snohomish stated:

With respect to the Supplemental Spill Surcharge item, this surcharge is a new cost for 2018, and thus is not included in Snohomish's 2017 actuals. In addition, Snohomish experienced financial impacts through its Slice product as a result of the spring spill regime. Snohomish's surplus Slice sales were lower, reducing its surplus market sales revenues by \$1.4 million compared to 2017. The spring spill regime and these impacts are expected to continue during the Exchange Period. Our interest is in making sure these costs are captured, and we are open to discussing how that is best accomplished.

Per Snohomish's data request response, and additionally for BPA's Issue List, Snohomish agrees with BPA in that this charge is not a new resource and does not meet materiality requirements. Therefore, BPA will exclude the Spill Surcharge costs from Snohomish's new resource tab. BPA may conduct further discussions on this matter at a later time.

**Final Decision:**

*BPA will remove the item 'Supplemental Spill Surcharge,' from the New Resource – Individual tab.*

**4.3 Decision on Draft Report Identification and Analysis of Unresolved Issues**

There were no unresolved issues in Snohomish's Draft ASC Report.

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## **5 GENERIC ISSUES AND STATEMENTS**

There are no generic issues to report for this ASC Filing.

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## **6 FY 2020-2021 ASC**

Snohomish's As-Filed 2017 Base Period ASC was \$53.99/MWh. As a result of adjustments made during the ASC Review Process, Snohomish's 2017 Base Period ASC decreased to \$52.69/MWh.

Snohomish's As-Filed Exchange Period ASC for FY 2020-2021 was \$60.45/MWh. As a result of adjustments made during the ASC Review Process, Snohomish's Exchange Period ASC for FY 2020-2021 decreased to \$54.68/MWh. Snohomish does not have any major resources or coming on line or being removed prior to or during the Exchange Period.

The Exchange Period ASC does not reflect any changes in NLSL status. See section 2.7 for potential adjustments to Exchange Period ASCs.

## **7 REVIEW SUMMARY**

This Final ASC Report is BPA's determination of Snohomish's FY 2020-2021 Base Period and Exchange Period ASCs based on the information and data provided by Snohomish, including comments, if any, received in response to the Draft ASC Report, and based on the professional review, evaluation, and judgment of BPA Staff.

BPA has resolved the issues set forth in Section 4 of this Report in accordance with the 2008 ASCM and with generally accepted accounting principles. The information and analysis contained herein properly establish Snohomish's ASC for FY 2020–2021.

## **8 APPROVAL ON BEHALF OF THE BONNEVILLE POWER ADMINISTRATION**

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

Issued in Portland, Oregon, this 25<sup>th</sup> day of July, 2019.

BONNEVILLE POWER ADMINISTRATION

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Vice-President for Northwest Requirements Marketing

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BONNEVILLE POWER ADMINISTRATION  
July 2019