5(c) (16 U.S.C. 839c(c)), or 5(d) (16 U.S.C. 839c(d)) of the Northwest Power Act for delivery in the Pacific Northwest region as defined by section 3(14) of the Northwest Power Act. 16 U.S.C. 839a(14).

Residential Purchase and Sales Agreement. The contract under section 5(c) of the Northwest Power Act between Bonneville and a Utility that defines and implements the power purchase and sale under the Residential Exchange Program.

Review Period. The period of time during which a Utility's Appendix 1 is under review by Bonneville. The Review Period begins on or about June 1, and ends on or about November 15 of the fiscal year prior to the fiscal year Bonneville implements a change in wholesale power rates.

Regulatory Body. A state commission, Consumer-owned Utility governing body, or other entity authorized to establish retail electric rates in a Jurisdiction.

RHWM Exchange Load. The Exchange Load as determined in section 20 of the Residential Purchase and Sales Agreement.

RHWM System Resources. The Rate Period High Water Mark (RHWM) as calculated in section 4.2.1 of the Tiered Rates Methodology plus the resource amounts used in calculating a customer's Contract High Water Mark (CHWM).

Tier 1 Priced-Power. Priority Firm Power as defined in Bonneville's Tiered Rates Methodology.

Tier 1 System Resources. Resources as defined in Bonneville's Tiered Rates Methodology.

Tiered Rates Methodology. The long-term methodology established by Bonneville for the determination of tiered wholesale power rates.

Utility. A Regional Power Sales Customer that has executed a Residential Purchase and Sales Agreement.

§ 301.3 Filing procedures.

(a) *Bonneville's ASC review procedures.* The procedures established by Bonneville's Administrator provide the filing requirements for all Utilities that file an Appendix 1 with Bonneville. Utilities must file Appendix 1s, ASC forecast models, and other required documents with Bonneville in compliance with Bonneville's ASC review procedures.

(b) *Exchange Period.* The Exchange Period will be equal to the term of Bonneville's Rate Period. ASCs will change during the Exchange Period only for the reasons provided in § 301.4.

§ 301.4 Exchange Period Average System Cost determination.

(a) *Escalation to Exchange Period.*

(1) This section describes the method Bonneville will use to escalate the Base Period ASC to and through the Exchange Period to calculate the Exchange Period ASC.

(2) Bonneville will escalate the Bonneville-approved Base Period ASC to the midpoint of the fiscal year for a one-year Rate Period/Exchange Period, and to the midpoint of the two-year period for a two-year Rate Period/Exchange Period to calculate Exchange Period ASCs.

(3) For purposes of the escalation referenced in paragraph (a)(2) of this section, Bonneville will use the following codes in the ASC forecast model to calculate the Exchange Period ASCs:

(i) A&G—Administrative and General.

(ii) CACNT—Customer Account.

(iii) CD—Construction, Distribution Plant.

(iv) CONSTANT—Constant.

(v) CSALES—Customer Sales.

(vi) CSERVE—Customer Service.

(vii) COAL—Coal.

(viii) DMN—Distribution Maintenance.

(ix) DOPS—Distribution Operations

(x) HMN—Hydro Maintenance.

(xi) HOPS—Hydro Operations.

(xii) INF—Inflation.

(xiii) NATGAS—Natural Gas.

(xiv) NFUEL—Nuclear Fuel.

(xv) NMN—Nuclear Maintenance.

(xvi) NOPS—Nuclear Operations.

(xvii) OMN—Other Production Maintenance.

(xviii) OOPS—Other Production Operations.

(xix) SNM—Steam Maintenance.

(xx) SOPS—Steam Operations.

(xxi) TMN—Transmission Maintenance.

(xxii) TOPS—Transmission Operations.

(xxiii) WAGES—Wages.

(4) Table 1 identifies which codes from paragraph (a)(3) of this section apply to the line items and associated FERC Accounts in the Appendix 1. Bonneville will use Global Insight as the source of data for the escalation codes indentified in paragraph (a)(3) of this section, except for the NATGAS and CONSTANT codes. For the NATGAS code identified in paragraph (a)(3)(xiii) of this section, Bonneville will calculate the escalation rate using Bonneville's most current forecast of natural gas prices. The code CONSTANT in paragraph (a)(3)(iv) of this section indicates that no escalation to the Account will be made.

(5) Bonneville will base the costs of power products purchased from Bonneville on Bonneville's forecast of prices for its products.

(6) Bonneville will escalate the Public Purpose Charge forward to the midpoint of the Exchange Period by the same rate of growth as total Contract System Load.

(7) If any of the escalators specified in paragraph (a) of this section are no longer available, Bonneville will designate a replacement source of such escalator(s) that, as near as possible, replicates the results produced by the prior escalator. If a replacement source is not available, Bonneville will use the INF escalation code identified in paragraph (a)(3)(xii) of this section as the replacement escalator.

(b) *Calculation of sales for resale and power purchases*—(1) *Long-term and intermediate-term sales for resale and power purchases*. Bonneville will use the INF escalation code identified in paragraph (a)(3)(xii) of this section to escalate long-term and intermediate-term (as defined by the Commission) firm purchased power costs and long-term and intermediate-term sales for resale revenues.

(2) *Short-term sales for resale and power purchases*. (i) The short-term purchases and short-term sales for resale for the Base Period will be used as the starting values. A Utility will be allowed to include new plant additions, and to use a utility-specific forecast for the price of purchased power and for the price of sales for resale in order to value purchased power expenses and sales for resale revenue to be included in the Exchange Period ASC.

(ii) Bonneville will use the following method to determine separate market prices to forecast short-term purchased power expenses and sales for resale revenues to calculate Exchange Period ASCs:

(A) The Utility's average short-term purchased power price and short-term sales for resale price will be calculated for each year for the most recent three years of actual data (Base Period and prior two years).

(B) The midpoint between the Utility's average short-term purchased power price and the average short-term sales for resale price will be calculated for each of the years in paragraph (b)(2)(ii)(A) of this section.

(C) The percentage spread around the Utility's midpoint between the average short-term purchase power price and short-term sales for resale price will be calculated for each of the years identified in paragraph (b)(2)(ii)(A) of this section.

(D) A weighted average spread for the Utility's most recent three years of actual data (Base Period and prior two years) will be calculated. The following weighting scale will be used:

(*1*) Three (3) times Base Period spread.

(*2*) Two (2) times (Base Period minus 1) spread.

(*3*) One (1) time (Base Period minus 2) spread.

(E) The Base Period midpoint calculated in paragraph (b)(2)(ii)(B) of this section will be escalated at the same rate as Bonneville's electric market price forecast.

(F) The weighted average spread calculated in paragraph (b)(2)(ii)(D) of this section will be applied to the escalated midpoint price calculated in paragraph (b)(2)(ii)(E) of this section to determine the purchased power price and sales for resale price to value purchased power expenses and sales for resale revenues to be included in the Exchange Period ASC.

(iii) The method described in paragraph (b)(2)(ii) of this section will be used to forecast the electric market price for power purchases needed to meet load growth not met by major resource additions, and to forecast the electric market price for any additional surplus power sales resulting from major resource additions.

(c) *Major resource additions and reductions and materiality thresholds.* (1) During the Exchange Period, Bonneville will allow changes to a Utility's ASC to account for major resource additions or reductions that are used to meet a Utility's retail load. These changes, however, must meet the requirements of paragraph (c)(3) of this section and the materiality threshold described in paragraph (c)(4) of this section in order for Bonneville to allow an ASC to change. The ASC reflecting the major resource addition or reduction will be determined by Bonneville in the ASC review process during the Review Period.

(2) For major resource additions, the change to ASC will become effective when the resource begins commercial operation, or power is received under the purchased power contract. For major resource reductions, the change to ASC will become effective when the resource is sold, retired, or transferred.

(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.

(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.

(5) At the time the Utility submits its Appendix 1 filing, the Utility will provide its forecast of major resource additions or reductions and all associated costs. The forecast will cover the period from the end of the Base Period to the end of the Exchange Period.

(6) Bonneville will calculate new transmission wheeling revenues associated with new transmission investment using the following formula:

TTWR = WR (before additions) * [(NTP (before additions) + NTA)/NTP (before additions)]

Where:

TTWR = total transmission wheeling revenues
WR (before additions) = wheeling revenues (before additions)
NTA = new transmission additions
NTP (before additions) = Net Transmission Plant (before additions)

(7) The forecast of major resource additions or reduction costs to be included in the Utility's Exchange Period ASC will be reviewed by Bonneville in the ASC review process that is conducted during the Review Period.

(8) All major resources included in an ASC calculation prior to the start of the Exchange Period will be projected forward to the midpoint of the Exchange Period.

(9) For each major resource addition or reduction that is forecasted to occur during the Exchange Period, Bonneville will calculate the difference in ASC between the ASC without the major resource addition or reduction and the ASC with the major resource addition or reduction (ASC delta) at the midpoint of the Exchange Period.

(10) Once the major resource addition or reduction becomes effective, as determined by paragraph (c)(2) of this section, Bonneville will add the ASC delta to the Utility's existing ASC to determine its new ASC.

(11) For purposes of calculating ratios with Distribution Plant, Bonneville will escalate the Base Period average per-MWh cost of Distribution Plant forward to the midpoint of the Exchange Period, and use the escalated

average cost to determine the distribution-related cost of meeting load growth since the Base Period.

(12) Bonneville will escalate the cost of General Plant, Accounts 389 through 399.1, forward to the midpoint of the Exchange Period by calculating the ratio of each Account's value in the Base Period to the sum of Production, Transmission, and Distribution plant values in the Base Period, and then multiplying the Base Period ratio times the forecasted value for Production, Transmission, and Distribution plant.

(13) Bonneville will issue procedural rules to ensure the confidentiality of information provided by Utilities regarding any major resource additions or reductions as part of its review process. Bonneville will provide parties with an opportunity to comment on the rules prior to their implementation in the review process. Failure to provide needed information may result in exclusion of the related costs from the Utility's ASC. However, load growth will be assumed to be met with purchases in the wholesale market, as described in paragraph (e) of this section. If the Utility fails to supply confidential resource data, it loses the difference between the cost of the resource and the price of electricity in the wholesale market.

(d) *Forecasted Contract System Load and Exchange Load.* All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss analysis as described in Endnote e of Appendix 1, with their Appendix 1 filings. The load forecast for Contract System Load and Exchange Load will start with the Base Period and extend through four (4) years after the Exchange Period. The load forecast for Contract System Load and Exchange Load will be provided on a monthly basis for the Exchange Period.

(e) *Load growth not met by major resource additions.* All forecast load growth not met by major resource additions will be met by purchased power at the forecasted utility-specific, short-term purchased power price.

(1) The Utility's forecast Load Growth will be met with electric market purchases priced at the Utility's forecast short-term purchased power price as determined in paragraph (b) of this section unless the Utility forecasts major resource additions.

(2) In the event of major resource additions, forecast Load Growth will be met by the major resource(s). If the major resource is less than total forecast load growth, the unmet Load Growth will be met with electric market purchases priced at the Utility's forecast short-term purchased power price.

(3) In the event the power provided by a major resource exceeds the Utility's forecast Load Growth, the excess power will be used to reduce the Utility's short-term purchases. If short-term power purchases are reduced to zero, any remaining power will be sold as surplus power at the short-term sales for resale price as determined in paragraph (b) of this section.

(f) *Changes to service territory.* In the event a Utility forecasts that it will acquire a new service territory, or lose a portion of its existing service territory, and the gain or loss of that territory results in a 2.5 percent or greater change to the Utility's Base Period ASC, the Utility must file two Appendix 1 filings with Bonneville as follows:

(1) First, a Base Period ASC that does not reflect the acquisition or loss of service territory; and

(2) Second, a Base Period ASC that incorporates the following changes:

(i) A forecast of the increase or reduction in Contract System Load associated with the acquisition or reduction in service territory.

(ii) A forecast of the increase or reduction in Contract System Cost associated with the acquisition or reduction of the service territory.

(iii) A forecast of capital and operating cost increases or reductions associated with the change in service territory.

(iv) A forecast of the changes in purchased power expenses, sales for resale revenues, and other debits or credits based on the changes in the service territory.

(3) Because the date of the actual change to the Utility's service territory could differ from the forecast date used to determine the ASC during the

Review Period, Bonneville will not adjust the Utility's ASC until the change in service territory takes place.

(g) *ASC determination for Consumer-owned Utilities that elect to execute Regional Dialogue High Water Mark contracts*. For Consumer-owned Utilities that elect to execute Regional Dialogue CHWM contracts, Bonneville will use the following approach:

(1) Use the RHWM System Resources as determined in the Tiered Rates Methodology (TRM) process.

(2) Determine the RHWM Exchange Load.

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

(4) Determine the fully allocated cost of resources used to meet Contract System Load that is not met by:

(i) The lesser of the Utility's RHWM or Forecast New Requirement, plus

(ii) Existing Resources for CHWM (as defined in the Tiered Rates Methodology).

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

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

(h) *Filing of Appendix 1*. Utilities must file an Appendix 1, including ASC information, by June 1 of each year, as required in § 301.3, for Bonneville's review and determination of a Base Period ASC. Utilities will file multiple, contingent, Base Period ASC filings to reflect changes to service territories as required in paragraph (f) of this section.

§ 301.5 Changes in Average System Cost methodology.

(a) The Administrator, at his or her discretion, or upon written request from three-quarters of the utilities that are parties to contracts authorized by section 5(c) of the Northwest Power Act, or from three-quarters of Bonneville's preference customers, or from three-quarters of Bonneville's direct-service industrial customers may initiate a consultation process as provided in section 5(c) of the Northwest Power Act. After completion of this process, Bonneville's Administrator may file the new ASC methodology with the Commission.

(b) The Administrator will not initiate any consultation process until one year of experience has been gained under the then-existing ASC methodology, that is, one year after the then-existing ASC methodology is adopted by Bonneville and approved by the Commission, through interim or final approval, whichever occurs first.

(c) The Administrator may, from time to time, issue interpretations of the ASC methodology. The Administrator also may modify the functionalization code of any Account to comply with the limitations identified in sections 5(c)(7)(A)–(C) of the Northwest Power Act or to conform to Commission revisions to the Uniform System of Accounts.

§ 301.6 Appendix 1 instructions.

(a) Appendix 1 is the form on which a Utility reports its Contract System Cost, Contract System Load, and other necessary data for the calculation of ASC. Appendix 1 is an electronic template consisting of seven schedules and several supporting files that must be completed by the Utility in accordance with these instructions and with the provisions of the endnotes following the schedules.

(b) Appendix 1 filings must be accompanied by an attestation statement of the Chief Financial Officer of the Utility or other responsible official who possesses the financial and accounting knowledge necessary to complete the attestation statement.

(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. In addition, the cost-of-service report must be reviewed by an independent accounting