124 FERC ¶ 61,312
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 301

Docket Nos. EF08-2011-000 and RM08-20-000

Sales of Electric Power to the Bonneville Power Administration; Revisions to Average System Cost Methodology

AGENCY: Federal Energy Regulatory Commission

ACTION: Interim Rule

SUMMARY: The Bonneville Power Administration (Bonneville) has submitted for the Federal Energy Regulatory Commission (Commission)'s approval a new methodology for determining the average system cost (ASC) of a utility's resources under the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). Bonneville requested that the Commission revise its regulations to incorporate the new methodology and to make the revised regulations effective October 1, 2008. On an interim basis, the Commission is conditionally revising its regulations governing the ASC methodology used by Bonneville in its Residential Exchange Program. The Commission also is requesting comments on whether, on a final basis, the Commission should approve the new ASC methodology proposed by Bonneville.

EFFECTIVE DATE: This interim rule is effective October 1, 2008.

COMMENT DATE: Comments on the interim rule are due [insert date that is 30 days after publication in the **FEDERAL REGISTER**].

ADDRESSES: You may submit comments on the interim rule, identified by Docket Nos. EF08-2011-000 and RM08-20-000, by one of the following methods:

- Agency web site: http://www.ferc.gov. Follow instructions for submitting comments via the eFiling link found in the Comment Procedures Section of the preamble.
- Mail: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to the Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, D.C. 20426. Please refer to the Comment Procedures Section of the preamble for additional information on how to file paper comments.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Sales of Electric Power to the Bonneville Power Administration; Revisions to Average System Cost Methodology	Docket Nos. EF08-2011-000 and RM08-20-000

INTERIM RULE

(Issued September 30, 2008)

1. The Bonneville Power Administration (Bonneville) has submitted for the Federal Energy Regulatory Commission (Commission)'s approval a new methodology for determining the average system cost (ASC) of a utility's resources under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).[1] Bonneville requested that the Commission revise its regulations to incorporate the new methodology and to make the revised regulations effective October 1, 2008. On an interim basis, the Commission is conditionally revising its regulations governing the ASC methodology used by Bonneville in its Residential Exchange Program. The Commission also is requesting comments on whether, on a final basis, the Commission should approve the new ASC methodology proposed by Bonneville.

[1] 16 U.S.C. 839(c).

Background

2. Section 5(c) of the Northwest Power Act provides for a Residential Exchange Program, which broadly speaking is designed to make the benefit of Bonneville's relatively low preference power rates available to residential customers of investor-owned utilities in the Pacific Northwest.[2] Although the Residential Exchange Program is available to any Pacific Northwest utility, the primary beneficiaries of the exchange are investor-owned utilities. Under the Residential Exchange Program, a utility may sell power to Bonneville at the average system cost of that utility's resources.[3] Bonneville then sells the same amount of power back to the utility at Bonneville's priority firm exchange rate.[4] The power exchange is generally viewed as a paper transaction.[5] In almost all instances, Bonneville makes a payment to the utility for the difference between the utility's average system cost and Bonneville's priority firm exchange rate, multiplied by the utility's residential and small farm load.

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[2] Id.

[3] 16 U.S.C. 839c(c)(1).

[4] Id. This rate is generally a lower rate.

[5] See CP Nat'l Corp. v. BPA, 928 F.2d 905, 907 (9th Cir. 1991) (quoting Public Utility Commissioner of Oregon v. BPA, 583 F. Supp. 752, 754 (D. Or. 1984)).

3. The Northwest Power Act does not define what constitutes the average system cost of a utility's resources.[6] Instead, the Act grants Bonneville's Administrator the authority to establish a methodology for determining an exchanging utility's average system cost through a stakeholder process in consultation with the Northwest Power Planning Council, Bonneville's customers, and appropriate State regulatory bodies in the region.[7] The Northwest Power Act directed the Administrator to exclude the following three types of costs from the average system cost: (1) the cost of additional resources in an amount sufficient to serve any new large single load of the utility; (2) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980; and (3) any costs of any generating facility which is terminated prior to initial operation.[8] Outside these explicit exclusions, the Northwest Power Act is silent on the costs that may be included or excluded in the average system cost. Bonneville's Administrator decides what costs should be considered when calculating the average system cost, and what process should be used to make that determination.

4. The Commission's role in this exchange program is two-fold. First, under section 5(c)(7) of the Act, while Bonneville develops a methodology for

[6] 16 U.S.C. 839c(c)(2).

[7] 16 U.S.C. 839c(c)(7).

[8] 16 U.S.C. 839c(c)(7)(A)-(C).

determining a utility's ASC (after consulting with various affected groups), the Commission must "review and approve" the methodology. Neither the statute nor its legislative history explains the nature of this review, however.[9]

5. The Commission's second role in the exchange program arises from its Federal Power Act (FPA)[10] responsibility to review the wholesale sales rates of individual investor-owned utilities; the Commission reviews the rates for such sales from the investor-owned utilities to Bonneville based on the ASC methodology. The Commission's existing rules (18 CFR 35.30 and 35.31) provide that the Commission will approve under the FPA any sale to Bonneville that is based on correct application of an approved methodology.[11]

6. On July 14, 2008, Bonneville filed a revised ASC methodology to replace the current ASC methodology approved by the Commission on a final basis in 1984, and codified in part 301 of the Commission's regulations (July 2008 Filing).[12] In its July 2008 Filing (which was corrected on September 12, 2008),[13]

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[9] Methodology for Sales of Electric Power to Bonneville Power Administration, Order No. 400, FERC Stats. & Regs. ¶ 30,601 at 31,161 (1984), reh'g denied, Order No. 400-A, FERC 30 FERC ¶ 61,108 (1985).

[10] 16 U.S.C. 824, 824d, 824e.

[11] Order No. 400, FERC Stats. & Regs. ¶ 30,601 at 31,161.

[12] 18 CFR Part 301.

[13] The July 2008 Filing was noticed in Docket No. EF08-2011-000 in the Federal Register, 72 FR 32633 (2008), with protests and interventions due on or before August 13, 2008. Timely motions to intervene and comments were filed by

(continued...)

Bonneville states that this is the first revision to its ASC methodology in 24 years, and reflects changes in the energy industry that have transpired during that time.

7. Bonneville explains that the stakeholder process that resulted in this revised ASC methodology began in May of 2007, following two Ninth Circuit opinions that held that Bonneville exceeded its statutory authority when it entered into certain Residential Exchange Program Settlement Agreements, and remanded Bonneville's WP-02 wholesale power rates for improperly allocating the costs of the Residential Exchange Program Settlement Agreements to its preference customers.[14] Bonneville explains that it ceased making Residential Exchange Program payments following these 2007 decisions.

8. Bonneville states that, before it can provide Residential Exchange Program payments, it must re-establish the Residential Exchange Program. According to Bonneville, this requires the following: (1) negotiation of Residential Purchase and Sale Agreements; (2) establishment of a Priority Firm Exchange rate in a

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Avista Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., Public Utility District No. 1 of Clark County, Washington, and the Public Utility District No. 1 of Grays Harbor County, Washington. The Public Power Council and the Public Utility District No. 1 of Snohomish County, Washington filed motions to intervene out of time. In addition, the Idaho Power Company filed comments and a partial protest. The Idaho Public Utilities Commission filed a notice of intervention and protest. Bonneville filed an answer to interested parties' comments and protests. Additionally, Bonneville filed an errata correction to its initial filing on September 12, 2008.

[14] See Portland General Elec. Co. v. BPA, 501 F.3d 1009 (9th Cir. 2007); Golden NW Aluminum, Inc. v. Bonneville Power Admin., 501 F.3d 1037 (9th Cir. 2007).

Northwest Power Act section 7(i)[15] rate adjustment proceeding; and (3) calculation of utilities' respective average system costs under an ASC methodology. Bonneville notes that, in a separate Bonneville proceeding, it negotiated new Residential Purchase and Sale Agreements to be effective October 1, 2008. And, in another Bonneville proceeding, it developed a revised priority firm exchange rate that it will submit to the Commission in a separate docket for interim approval. Bonneville explains that it must ensure that an ASC methodology is in effect to determine exchanging utilities' average system costs to implement the Residential Exchange Program on October 1, 2008. Bonneville, therefore, requests the Commission to grant interim approval of the revised ASC methodology no later than October 1, 2008.

9. In its July 2008 Filing, Bonneville explains that the revised ASC methodology retains characteristics of the current ASC methodology. Bonneville explains, further, that the key differences are in how average system costs are calculated as well as the substance of the costs included and excluded from the average system cost calculation. Bonneville states that the revised ASC methodology adopts a streamlined approach to the average system cost calculations by using a different source of average system cost data, i.e., FERC Form No. 1 data, instead of state retail rate orders. Bonneville notes that, in addition, it proposes to adjust the average system costs less frequently. Bonneville

[15] 16 U.S.C. 839e.

asserts that the revised ASC methodology allows each utility to file a single, combined average system cost for its entire within-region service territory as opposed to an average system cost for each state jurisdiction in which it operates

10. Bonneville also explains that it is proposing to establish a two-year average system cost that will correspond with its two-year wholesale power rate periods. Bonneville explains, further, that utilities' average system costs will stay fixed except for pre-determined adjustments to reflect the costs of new resources incurred during the rate/exchange period. According to Bonneville, these features will lessen the number of average system costs filings reviewed by Bonneville and the Commission.

11. Bonneville explains that the revised ASC methodology also changes the average system cost treatment of certain costs. Bonneville states that it is allowing utilities to exchange a full return on equity (instead of the weighted cost of debt); the utility's marginal Federal income tax; and the utility's transmission plant costs.

12. Bonneville requests Commission approval of this new ASC methodology.

Discussion

13. For the reasons discussed below, the Commission has determined to conditionally grant interim approval of Bonneville's new ASC methodology. We note, however, that the methodology must be further reviewed before final approval can be given; this review cannot be completed during the short time period in which the methodology has been before the Commission.

14. Interim approval is necessary to further the intent of the Northwest Power Act. An approved (by the Commission) ASC methodology is fundamental to the Residential Exchange Program found in section 5 of the Northwest Power Act The methodology defines the rates at which sales will be made to Bonneville which, when made, will permit exchanges to occur.

15. This warrants approval on an interim basis of Bonneville's revised ASC methodology. However, the Commission is obligated to review and approve the methodology in accordance with certain procedures and its responsibilities to protect the public interest, and the Commission has yet to finish its review of the proposed methodology. For these reasons, the approval granted here is interim only.

16. Moreover, such interim approval must be conditioned to ensure that the public interest is protected during the time period the interim approval is in place. The revised ASC methodology will affect rates paid by, and to, Bonneville. To the extent that the ASC methodology finally approved by the Commission differs from that filed by Bonneville in its July 2008 filing, and which is approved on an interim basis here, the rates paid may be different from the rate under the ASC methodology finally approved by the Commission. The Commission must be assured that any such difference can be corrected, through refund or surcharge, to the extent of the difference, should that be appropriate. To ensure this result, the

Commission grants interim approval only conditionally and subject to refund or surcharge.[16]

17. The Commission attaches this condition with the full awareness that, by so doing, some uncertainty is injected into the exchange process. Rates paid may be too high or too low, depending upon the ASC methodology finally approved by the Commission. However, under the circumstances, some uncertainty is unavoidable. The Commission staff has completed a preliminary review of the methodology, however, and is satisfied that such uncertainty is minimal. Moreover the methodology is a product not only of a stakeholder process, which should serve to minimize any uncertainty, but also of notice and comment procedures. This provides good grounds for finding that, for purposes of interim approval, due process has been observed.[17]

Paperwork Reduction Act Statement

18. A Paperwork Reduction Act Statement is not required for this interim rule because the regulations adopt a methodology used by a federal power marketing administration, in this case Bonneville.

Environmental Analysis

19. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant

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[16] Order No. 400, FERC Stats. & Regs. ¶ 30,601 at 31,162.

[17] Id.

adverse effect on the human environment.[18] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in these exclusions are Commission actions addressing proposed public utility rates and Commission confirmation, approval, and disapproval of rate filings submitted by federal power marketing administrations under the Northwest Power Act.[19] The actions herein fall within this categorical exclusion in the Commission's regulations.

Regulatory Flexibility Act

20. The Regulatory Flexibility Act of 1980 (RFA)[20] generally requires a description and analysis of the effect that an interim rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities.

21. The Commission concludes that this interim rule will not have such an impact on a substantial number of small entities. Bonneville is a federal power marketing administration. And the investor-owned utilities which are participating

[18] Regulations Implementing the National Environmental Policy Act, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[19] 18 CFR 380.4(a)(15).

[20] 5 U.S.C. 601-12.

in the Residential Exchange Program are not small entities.[21] Moreover, the number of utilities participating in the program is not substantial; only nine utilities whose rates are within the Commission's jurisdiction are participating in the program.

22. For these reasons, the Commission certifies under the RFA that this interim rule will not have a significant economic effect on a substantial number of small entities.

Comment Procedures

23. The Commission invites interested persons to submit comments on the matters and issues raised by the proposed revised ASC methodology. Comments are due [insert date that is 30 days after publication in the **FEDERAL REGISTER**].[22] Comments must refer to Docket Nos. EF08-2011-000 and RM08-20-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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[21] 5 U.S.C. § 602(3) citing section 3 of the Small Business Act, 15 U.S.C. § 632. Section 3 of the Small Business Act defines "small business concern" as a business which is independently owned and operated, and which is not dominant in its field of operation.

[22] All motions to intervene, comments, and protests, and all notices of intervention filed in Docket No. EF08-2011-000 will be considered to have been filed in Docket No. RM08-20-000. All comments and protests filed in Docket No. EF08-2011-000 will be addressed in the final rule issued in Docket No. RM08-20-000. Intervenors in Docket No. EF08-2011-000 wishing to file additional comments may do so.

24. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

25. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to the Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, D.C. 40246.

26. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

Document Availability

27. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's home page http://www.ferc.gov and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 P.M. Eastern time) at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

28. From the Commission's home page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the document number excluding the last three digits of this document in the docket number field.

29. User assistance is available for eLibrary and the Commission's web site during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at <public.referenceroom @ferc.gov>.

Effective Date

30. For the reasons discussed above, the Commission finds good cause under section 553(d)(3) of the Administrative Procedure Act[23] to make this rule effective immediately, rather than 30 days after publication in the Federal Register. The long-term impact of delayng early implementation of a new revised ASC methodology justifies its immediate effectiveness. This interim rule, therefore, will take effect on October 1, 2008.

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[23] 5 U.S.C. 553(d)(3).

List of subjects in 18 CFR Part 301

Electric power rates; Electric utilities; Reporting and recordkeeping requirements

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

In consideration of the foregoing, the Commission amends part 301, Title 18, Chapter I of the Code of Federal Regulations, as follows:

1. Part 301 is revised to read as follows:

PART 301 – AVERAGE SYSTEM COST METHODOLOGY FOR SALES FROM UTILITIES TO BONNEVILLE POWER ADMINISTRATION UNDER NORTHWEST POWER ACT

Sec.

Authority: 16 U.S.C. § 839-839h.

§ 301.1 Applicability.

The regulations in this part provide the procedures by which regional utilities will submit Average System Cost (ASC) filings to the Bonneville Power Administration (Bonneville), and by which Bonneville will review those filings. Bonneville's review will determine a utility's ASC for the purpose of participating in the Residential Exchange Program under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. § 839c(c).

§ 301.2 Definitions.

For purposes of this section, the following definitions apply:

Appendix 1. Appendix 1 is the electronic form on which a utility reports its Contract System Costs and other necessary data to Bonneville for the calculation of the utility's Base Period.

Average System Cost (ASC). The rate charged by a utility to Bonneville for the agency's purchase of power from the utility under section 5(c) of the Northwest Power Act for each Exchange Period, and is the quotient obtained by dividing the Contract System Costs by Contract System Load.

Base Period. The calendar year of the most recent Form 1 data.

Base Period ASC. The ASC determined in the Review Period using the utility's Base Period data.

Contract High Water Mark (CHWM). The average MW amount used to define access to Tier 1-priced power. CHWM is equal to the adjusted historical load for each customer proportionately scaled to Tier 1 System Resources and adjusted for conservation achieved. The CHWM is specified in each eligible customer's Contract High Water Mark Contract.

Commission. The Federal Energy Regulatory Commission.

Contract System Costs. The utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in, and subject to, the provisions of Appendix 1. Under no circumstances will Contract System Costs include costs excluded from ASC by section 5(c)(7) of the Northwest Power Act.

Contract System Load. The total regional retail load included in Form 1, or for a consumer-owned utility (preference customers), the total retail load from the most recent annual audited financial statement as adjusted pursuant to the ASC methodology.

Exchange Period. The period during which a utility's Bonneville-approved ASC is effective for the calculation of the utility's Residential Exchange Program benefits. The initial Exchange Period under this ASC methodology is from October 1, 2007, through September 30, 2009. Subsequent Exchange Periods will be the period of time concurrent with the Bonneville rate period beginning October 1, or the effective date of Bonneville's rate period.

Exchange Period ASC. The Base Period ASC escalated to a year(s) consistent with the Exchange Period.

Form 1. The annual filing submitted to the Federal Energy Regulatory Commission required by 18 CFR § 141.1.

Jurisdiction. The service territory of the utility within which a particular regulatory body has authority to approve a utility's retail rates. Jurisdictions must be within the Pacific Northwest region as defined in the Northwest Power Act.

Labor Ratios. The ratios which assign costs on a pro rata basis using salary and wage data for Production, Transmission, and Distribution/Other functions included in the utility's most recently filed Form 1. For consumer-owned utilities, comparable data will be used based on the cost-of-service study used as the basis for retail rates at the time of review.

New Large Single Load. That load defined in section 3(13) of the Northwest Power Act, and determined by Bonneville as specified in power sales contracts and Residential Sale and Purchase Agreements (RPSA) with its Regional Power Sales Customers.

Public Purpose Charge. Any charge based on a utility's total retail sales in a jurisdiction that is given to independent nonprofit entities or agencies of state and local governments for the purpose of funding within the utility's service territory including:

(a) Conservation programs in lieu of utility conservation programs; and

(b) Acquisition of renewable resources.

Rate Period High Water Mark (RHWM). The amount used to define each customer's eligibility to purchase power at a Tier 1 price for the relevant Rate Period, subject to the customer's New Requirement, expressed in average megawatts (aMW). RHWM is equal to the customer's CHWM as adjusted for changes in Tier 1 System Resources. The RHWM is determined for each eligible customer in the RHWM Process preceding each rate case.

Regional Power Sales Customer. Any entity that can contract directly with Bonneville for the purchase of power under sections 5(b), 5(c), or 5(d) of the Northwest Power Act for delivery in the region as defined by section 3(14) of the Northwest Power Act.

Residential Purchase and Sale Agreement (RPSA). The power sales contract under section 5(c) of the Northwest Power Act between Bonneville and the utility that defines and implements the power purchase and sale.

Review Period. The period of time during which a utility's Appendix 1 is under review by Bonneville. The Review Period begins on 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 or consumer-owned utility governing body, or other entity authorized to establish retail electric rates in a Jurisdiction.

Utility. An investor-owned or consumer-owned (preference) Regional Power Sales Customer that has executed a Residential Purchase and Sale Agreement.

§ 301.3 Filing procedures.

The following procedures provide the filing requirements for all utilities that file an Appendix 1 to participate in the Residential Exchange Program. Utilities must file an Appendix 1 with Bonneville to permit the calculation of each utility's ASC.

(a) Initial Exchange Period (2009).

(1) A utility's ASC for fiscal year FY 2009 will be determined by Bonneville in accordance with this ASC methodology, and will constitute the effective ASC for the Residential Exchange Program effective October 1, 2008, unless:

(i) The Commission fails to approve the methodology;

(ii) The Commission amends the methodology in a manner that changes the utility's ASC established by Bonneville; or

(iii) The methodology is legally challenged, and not affirmed on appeal by the United States Court of Appeals for the Ninth Circuit.

(iv) The Base Period Appendix 1 filing will be from CY 2006.

The Initial Exchange Period will begin October 1, 2008 provided that the Commission grants the methodology interim or final approval by that date. The Initial Exchange Period will end on September 30, 2009.

(2) Since the Initial Exchange Period begins on October 1, 2008, and the utility filings for FY 2008 are due that same day, Bonneville will pay the exchanging utilities based on their October 1, 2008 filed ASC, and calculate a *true-up to the final* ASC *after the Bonneville Review Period is concluded,* and Bonneville issues the final ASC reports. If a utility fails to file an Appendix 1 by October 1, 2008, Bonneville will follow the procedures outlined in paragraphs (d) and (e) of this section. Prior to the commencement of the Bonneville review process, Bonneville will publish a schedule for the review of the filings. Bonneville may issue a schedule different from the prescribed schedule in order to ensure that ASCs are established in time to be trued-up during FY 2009.

(b) Second Exchange Period (FY 2010-2011).

(1) For the Second Exchange Period, utilities are required to submit their ASC filings by October 1, 2008 for FY 2010-2011. If a utility fails to file an Appendix 1 by October 1, 2008, Bonneville will follow the procedures outlined in paragraphs (d) and (e) of this section. Prior to the commencement of the Bonneville Review Period, Bonneville will publish a schedule for review of the filings. Bonneville may issue a schedule different from the prescribed schedule in order to ensure that ASCs are established in time to be incorporated in Bonneville's FY 2010-2011 wholesale power rate case.

(2) After Bonneville's review process is concluded, Bonneville will issue utility ASC Reports to reflect the final ASCs for the FY 2010-2011 rate period.

(c) Subsequent Exchange Periods.

(1) Subsequent Exchange Periods will be equal to the term of subsequent Bonneville wholesale power rate periods. ASCs will change during the Exchange Periods only for the reasons provided in paragraph (a)(1) of this section.

(2) Except as provided for in the Initial and Second Exchange Periods, utilities must file electronically at least one Appendix 1 with Bonneville by June 1 of each year. In years when Bonneville is not conducting a review process, these filings will be for informational purposes only, and will not change a utility's ASC. The Appendix 1 must be accompanied by supporting documentation, studies and analyses used to prepare the Appendix 1.

(i) For investor-owned utilities, Appendix 1 must be based on the utility's most recently filed Form 1 and limited information from prior Form 1 filings as required.

(ii) For consumer-owned utilities, Appendix 1 must be based on the utility's most recent audited financial information, and must be accompanied by a cost-of-service analysis.

(iii) Each Appendix 1 must contain an attestation signed by a senior officer of the utility stating that the filing has been compiled in accordance with the Commission's Uniform System of Accounts, the ASC methodology in part 301 of the Commission's regulations, and Generally Accepted Accounting

Principles, and is consistent with applicable orders and policies of the utility's Regulatory Body.

(d) Failure to file an Appendix 1. If a utility fails to timely file an Appendix 1, and refuses to cure the problem within the period to cure provided in paragraph (f) of this section, Bonneville will make the utility's Appendix 1 filing. The utility will waive its right to participate in the ASC review proceeding to establish its ASC. All other parties will be permitted to participate, and present arguments challenging the utility's ASC.

(e) Filing a patently deficient Appendix 1. If a utility files its initial Appendix 1, and it is patently deficient as determined by Bonneville, and the period to cure, as outlined in paragraph (f) of this section, has expired, Bonneville will make the utility's Appendix 1 filing. The utility will waive its right to participate in the ASC review proceeding to establish its ASC. A utility filing a patently deficient ASC filing must allow Bonneville the discretion to set its ASC for the Exchange Period, and Bonneville will not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

(f) Period to cure. If a utility fails to timely file an Appendix 1, or if it files an ASC that Bonneville determines is patently deficient, Bonneville will provide the utility with written notice and a period of seven (7) calendar days within which to file or to re-file a new or corrected Appendix 1. In the event the utility fails to file or re-file by the end of the seven-day cure period, or if the refiled Appendix 1 is determined patently deficient, Bonneville will make the utility's Appendix 1 filing. The utility will waive its right to participate in the ASC review proceeding to establish its ASC. All other parties will be permitted to participate and present arguments challenging the utility's ASC. A utility filing a patently deficient ASC filing will allow Bonneville discretion to set its ASC for the Exchange Period, and Bonneville will not be required to include any proposed adjustments for resources changes or changes in service territories in the Appendix 1 filing.

(g) Failure to file an Appendix 1 because of a new Residential Purchase and Sale Agreement. After the Initial and Second Exchange Periods, if a utility fails to file its Appendix 1 by June 1 because it executed a Residential Purchase and Sale Agreement after commencement of a Review Period or during the subsequent Exchange Period, Bonneville may set the utility's ASC equal to the Priority Firm Exchange rate until the end of the Exchange Period.

(h) Notice of filing of Appendix 1. (1) After a utility files an Appendix 1 electronically, Bonneville will post the filings and non-confidential documentation on its electronic web site. Access to the information will be subject to any confidentiality rules or requirements established by Bonneville.

(2) Bonneville will advise parties of the right to file a petition to intervene in Bonneville's ASC review process.

§ 301.4 **Bonneville Power Administration's Average System Cost Review Process.**

During a Review Period, the following procedures apply. These procedures will not apply to informational ASC filings made outside of a Review Period.

(a) Bonneville may petition to intervene in each retail rate proceeding for each utility participating in the Residential Exchange Program. If Bonneville or any of its Regional Power Sales Customers is denied the right to intervene in a retail rate review proceeding of a filing utility when the intervention is for purposes of obtaining any information regarding costs or facts relevant to the determination of a utility's ASC (after making a good faith effort to intervene in the retail rate proceeding and timely complying with applicable procedures to intervene in the retail rate proceeding), Bonneville may set that utility's ASC equal to the Priority Firm Exchange Rate for the following Exchange Period. Exchanging utilities must provide Bonneville and Regional Power Sales Customers with at least 60 days notice of their intent to change their retail rates.

(b) Each Appendix 1 will be reviewed by Bonneville or its designee and subject to a public process to determine whether the Contract System Costs are consistent with Generally Accepted Accounting Principles for electric utilities, whether Contract System Costs contain only allowed costs, and whether the revised Appendix 1 complies with the requirements of the ASC methodology, including applicable definitions and requirements incorporated from the Commission's Uniform System of Accounts. In addition, each Appendix 1 will be reviewed by Bonneville or its designee to determine whether the Contract System Load used by the utility is an appropriate load for purposes of the utility's ASC computation.

(c)(1) In calculating ASCs, Bonneville will make an independent determination of the following:

(i) The appropriateness of the inclusion of costs;

(ii) The reasonableness of the costs included in Contract System Costs; and

(iii) The appropriateness of Contract System Loads.

(2) Bonneville will not be obligated to pay an ASC different than the ASC based on Contract System Costs and Contract System Load as determined by Bonneville.

(3) If a final order of the Commission or a reviewing court rejects Bonneville's ASC determination, the ASC payable by Bonneville will be the ASC as revised by Bonneville on remand.

(d) The Appendix 1 filing will be subject to review as follows:

(1) The Bonneville review process (not including the Initial and Second Exchange Periods) commences June 1 (Day 1) of the Review Period (or other date as may be established by Bonneville). Bonneville will review all utilities' ASCs concurrently in a public process.

(2) The dates identified in these regulations and those listed on the sample time line shown in § 301.7 are generic, and intended to illustrate a time line that is representative of the ASC review process. Unless specified, the days represent calendar days. Each spring, prior to the Review Period, Bonneville will post on its ASC methodology web site (http://www.bpa.gov/corporte/finance/ascm) or its successor, a detailed schedule, accommodating the applicable holidays and weekends, that will be the official schedule for that Review Period.

(e) Review Period time line.

(1) Day 1. Utility filings due to Bonneville.

(2) Day 3. Bonneville posts the utility filings to its electronic web site. Access to the information will be subject to any confidentiality rules or requirements established by Bonneville.

(3) Day 7. Deadline to file utility-specific petitions to intervene with Bonneville for the review process. Any Regional Power Sales Customer or state utility Regulatory Body who so requests will be accorded party status for Bonneville's ASC review process if the request is received by the established deadline. Other interested parties also may submit a petition to intervene, and Bonneville will grant party status at its discretion. Petitions to intervene must state with particularity the petitioner's interest in the ASC review proceeding. Petitions to intervene must be filed for each respective Bonneville review proceeding in order for a party to comment on the individual proceedings. The filing utility is

automatically a party to its own ASC review proceeding. Bonneville will grant or deny petitions to intervene within seven (7) days after the deadline for filing the petitions.

(4) Day 10. Bonneville grants or denies petitions to intervene.

(5) Day 11-66. Parties allowed to submit data requests.

Bonneville and parties will file data requests electronically with the utility and Bonneville. Bonneville will make data requests available to all parties. Each utility will respond to requests for information relevant to the utility's Appendix 1 filing, provided that the furnishing of proprietary or confidential information to any party may be made contingent on the granting of proper safeguards to prevent unauthorized use or disclosure. The responses must be sent to the requester and Bonneville.

(i) For each data request, the responding utility has seven (7) days to provide the requested data or object. If a utility files an objection to a data request, the party submitting the data request has four (4) days to respond to the objection. After the response to the objection is received, or the four (4) days to respond has elapsed, Bonneville then has seven (7) days to issue a ruling as to whether the utility's objection will be sustained or overruled. If the objection is overruled, the utility must provide the data requested within seven (7) days after the ruling. If a utility does not provide the requested data, Bonneville may, in its discretion, remove from Contract System Costs all costs associated with the data not provided.

(6) Day TBD. Bonneville will begin workshops on all Appendix 1 filings based on the specific schedules. Utilities filing an Appendix 1will have staff or agents available for questioning by Bonneville and other parties to the proceeding. The primary purpose of the first workshop is to clarify data, work papers, supporting documentation and assumptions used to prepare the Appendix 1.

(7) Day 88. By this day, Bonneville and parties may file electronically with Bonneville an issue list identifying contested elements of a utility's ASC filing and the basis for the parties' issues. Bonneville will make the issue lists available to all parties.

(8) Day 102. By this day, each filing utility will electronically file a response to the issue lists. Bonneville and other parties also may file comments in response to the issue lists.

(9) Day 108. By this day, a workshop will be held to discuss and resolve the issues raised by parties through their issue lists.

(10) Day 111. Requests for oral argument before the Administrator or his/her designee must be submitted in writing to Bonneville by this day. The requests must contain a statement providing reasons why the party believes oral argument is necessary.

(11) Day 114. By this day, Bonneville, at its discretion, may grant or deny any request for oral argument.

(12) Day 123. In the event a request for oral argument is granted, the requesting party will present its arguments first. Responding parties will present their arguments following the requesting party's arguments. The Administrator or his/her designee, at his discretion, may provide an opportunity for the requesting party to reply. Oral arguments will be presented no later than this day.

(13) Day 141. By this day, Bonneville will publish for comment, and serve electronically draft utility ASC reports on all parties. The reports will contain analyses and decisions on all contested issues raised in the ASC review process.

(14) Day 154. By this day, the utility and parties may file comments on the draft utility ASC reports.

(15) Day 167. The Bonneville Administrator will issue final utility ASC reports.

(16) If Bonneville has not issued the final utility ASC reports by the end of the Review Period, the ASC filed by the utility will be the Exchange Period ASC until the date Bonneville issues the final utility ASC reports. The final ASCs determined by Bonneville will then be the Exchange Period ASCs effective back to the beginning of the Exchange Period and until the end of the Exchange Period.

§ 301.5 Exchange Period Average System Cost determination.

(a) Escalation to Exchange Period.

(1) Bonneville will escalate Bonneville-approved Base Period costs 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.

(2) For purposes of the escalation referenced in paragraph (a)(1) of this section, Bonneville will use Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), Operations & Maintenance and General & Administrative expenses; and Bonneville's forecast of market prices for investor-owned utility purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; and Bonneville's forecast of natural gas prices and Bonneville's estimates of the rates it will charge for its Priority Firm and other products.

(3) With the exception of the natural gas escalator provided by Bonneville, the following list of acronyms defines Global Insight's escalation codes. These escalators will be used for each line item included in Appendix 1.

(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) HMN – Hydro Maintenance.

(x) HOPS – Hydro Operations.

(xi) INF – Inflation.

(xii) NATGAS – Natural Gas.

(xiii) NFUEL – Nuclear Fuel.

(xiv) NMN – Nuclear Maintenance.

(xv) NOPS – Nuclear Operations.

(xvi) OMN – Other Production Maintenance.

(xvii) OOPS – Other Production Operations.

(xviii) SMN – Steam Maintenance.

(xix) SOPS – Steam Operations.

(xx) TMN – Transmission Maintenance.

(xxi) TOPS – Transmission Operations.

(xxii) WAGES – Wages.

(4) If any of the escalators specified in the ASC methodology are no longer available, Bonneville will designate a replacement source of escalators that, as near as possible, replicates the results produced by the prior escalator, and, if a replacement source is not available, the replacement escalator will be the forecast of the GDP Price Deflator.

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

(b) Treatment of sales for resale and power purchases.

(1) Bonneville will escalate long-term and intermediate term (as defined by the Commission) firm purchased power costs and sales for resale revenues at the rate of inflation.

(2) Bonneville will not normalize short-term purchases and sales for resale. The short-term purchases and 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 use a utility-specific forecast for the price of purchased power and sales for resale price to value purchased power expenses and sales for resale revenue to be included in the Exchange Period ASC.

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

(i) 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).

(ii) The midpoint between the utility's average short-term sales for resale price will be calculated for each of the years in paragraph (b)(3)(i) of this section.

(iii) 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 escalated for each of the years identified in paragraph (b)(3)(i) of this section.

(iv) 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:

(A) Three (3) times Base Period spread.

(B) Two times (Base Period minus 1) spread.

(C) One time (Base Period minus 2) spread.

(v) The Base Period midpoint price calculated in paragraph (b)(3)(ii) of this section will be applied to the forecasted midpoint calculated in paragraph (b)(3)(iv) of this section to determine the purchased power and sales for resale price, to value purchased power expenses and sales for revenue to be included in the Exchange Period ASC.

(vi) The weighted average spread calculated in paragraph (b)(3)(iv) of this section to determine the purchased power and sales for resale price, to value purchased power expenses and sales for resale revenue to be included in the Exchange Period ASC.

(vii) This same method will be used to calculate the market price forecast for short-term, purchased power expense and sales for resale revenues for use in the load growth not met by new resource additions.

(c) <u>Major resource additions and materiality thresholds</u>.

(1) During the Exchange Period, Bonneville will allow changes to a utility's ASC to account for major new purchase power contracts or major new resource additions that come on-line, and are used to meet the utility's retail load.

These changes, however, have to meet a materiality threshold in order for Bonneville to allow an ASC to change. These ASCs will be determined by Bonneville during the Review Period. The changes to the ASC will become effective when the resource begins commercial operation, or power is received under the purchased power contract. The criteria also will apply to resources that are sold, transferred, or retired.

(2) Bonneville will use the following method to determine the changes in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold. These additions will include new production resource investments, 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.

(3) Bonneville will apply a materiality threshold of 2.5 percent change in a utility's Base Period ASC to determine when a change in ASC will be allowed for resource additions or reductions. Bonneville will allow a utility to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

(4) At the time the utility submits its Appendix 1 filing, the utility will provide its forecast of major new resource addition(s) and all associated costs.

The forecast will cover the period from the end of the Base Period to the end of the Exchange Period.

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

NTWR = WR (before additions) * [NTP (before additions) + NTA)

NTP (before additions)]

Where:

NTWR = New transmission wheeling revenues

WR (before additions) = wheeling revenues (before additions)

NTP (before additions) = Net Transmission Plant (before additions)

NTA = new transmission additions

(6) The forecast of the major new resource costs to be included in the utility's Exchange Period ASC will be reviewed and determined during the Review Period.

(7) All major new 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.

(8) For each major new resource addition forecast to be available to meet regional retail load during the Exchange Period, Bonneville will calculate the difference in ASC between the ASC without the new resource and the ASC with the new resource (the ASC delta) at the midpoint of the Exchange Period.

(9) When the resource comes online, Bonneville will add the ASC delta to the utility's existing ASC to determine its new ASC.

(10) The steps in paragraphs (c) (3) through (c)(9) of this section will be used for resources that are sold, transferred, or retired.

(11) 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. This cost will be included in the Exchange Period ASC.

(12) Bonneville will issue procedural rules to ensure the confidentiality of information provided by utilities regarding any new major resource additions 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, as is the case for other utilities that do not have major resource additions in a particular year, load growth will be assumed to be met with purchases in the wholesale market, as described in paragraph (e) of this section. What the utility loses by not supplying confidential resource data is the difference between the cost of the resource and the price of electricity in the wholesale market.

(d) Forecasted Contract System 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 study as described in endnote e/ of Appendix 1, with their Appendix 1 listing. 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 new resource additions. All forecast load growth not met by new 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 market purchases priced at the utility's forecast short-term, purchased power price unless the utility forecasts major resource additions.

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

(3) In the event that the power provided by a new resource exceeds the utility's forecast load growth, the excess will be sold as surplus power into the market, and priced at the utility's forecast 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 service territory, and the resulting change in ASC falls within the 2.5 percent or greater materiality threshold, the utility will submit two ASC filings.

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

(2) A second filing that incorporates the following:

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

(ii) The forecast of the increase or reduction in Contract System Costs associated with the acquisition or relinquishment of the service territory.

(iii) In addition to including the forecast of capital and operating cost increases or reductions associated with the change in service territory, the utility must forecast the changes in purchased power expense, sales-for-resale credit and other costs based on the changes in the service territory.

(iv) 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) <u>ASC determination for customer-owned utilities that elect to execute Regional Dialogue High Water Mark contracts</u>. Bonneville will use the following approach:

(1) Use the RHWM System Load as determined in the Tiered Rates methodology process.

(2) Determine the RHWM Exchangeable Load (Residential/Small Farm Load).

(3) During the ASC review process, the utility must submit the data necessary to determine the fully-allocated unit cost of resources in excess of the resource amounts used to calculate its CHWM.

(4) Calculate the utility's total unadjusted Contract System Cost.

(5) Calculate a load growth credit, i.e., {(Current System Load minus RHWM System Load) * Unit costs from paragraph (g)(3) of this section}.

(6) Total Exchange Contract System Cost = Total Unadjusted Contract System Cost minus load growth revenue credit from paragraph (g)(5) of this section.

(7) HWM Average System Cost = Total Exchangeable Contract System Cost/RHWM System Load.

(h) Filing of Appendix 1. Utilities must file ASC information by June 1 each year, as required in § 301.2, 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.

§ 301.6 Change 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, the Administrator may file the new ASC methodology with the Commission. However, the Administrator will not initiate any consultation process until one year of experience has been gained under the then-existing ASC methodology, 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.

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

§ 301.7 Sample time line review procedures.

(a) Bonneville's ASC review process of the utilities' Appendix 1 occurs only in the year before Bonneville establishes new Wholesale Power Rate Schedules. However, utilities are required to file an Appendix 1 by June 1 of each year so that Bonneville can maintain current data.

(b) The following schedule is a generic schedule that is representative of the time line for the ASC review process. Each spring in the year prior to Bonneville's implementation of new Wholesale Power Rates, Bonneville will post a detailed schedule incorporating the applicable holidays and weekends. Deadlines end at 5 p.m., Pacific Prevailing Time, of the due date.

(1) June 1 – Utilities file electronic Appendix 1s with Bonneville.

(2) June 7 – Deadline to file petitions to intervene with Bonneville.

(3) June 10 – Bonneville grants or denies petitions to intervene.

(4) June 11 – Begin Data Request period.

(5) TBD – Workshop(s) on utilities' Appendix 1 filings.

(6) Aug 22 – End Data Request period.

(7) Aug 27 – Deadline for Bonneville's and parties' issue lists on utilities' filings.

(8) Sept 10 – Deadline for reply issue lists from all parties on utilities' filings.

(9) Sept 16 – Workshop to discuss issue lists on utilities' filings.

(10) Sept 19 – Deadline to request oral argument.

(11) Sept 22 – Bonneville grants or denies requests for oral argument.

(12) Oct 1 – Oral argument (if granted).

(13) Oct 19 – Bonneville publishes draft ASC Report.

(14) Nov 1 – Deadline for utilities' and parties' comments on draft ASC Report.

(15) Nov 14 – Administrator issues final ASC Report.

§ 301.8 <u>Appendix 1 instructions</u>.

(a) Appendix 1 is the form on which a utility reports its Contract System Costs, Contract System Loads, 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 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 Form 1 filing 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 Costs. In addition, the cost-of-service report must be reviewed by an independent accounting or consulting firm. The cost-of-service report must be accompanied by a report from an independent accounting firm or consulting firm that outlines the review work that was performed in preparing the cost-of-service report along with an assurance statement that the information contained in the cost-of-service report is presented fairly in all material respects.

(e) The Appendix 1 template is available electronically at http://www.bpa.gov/corporate/finance/ascm/ , or its successor site. The primary schedules are:

(1) Schedule 1: Plant Investment/Rate Base

(2) Schedule 1A: Cash Working Capital

(3) Schedule 2: Capital Structure and Rate of Return

(4) Schedule 3: Expenses

(5) Schedule 3A: Taxes

(6) Schedule 3B: Other Included Items

(7) Schedule 4: Average System Cost

(f) The filing utility must reference and attach work papers, documentation, and other required information that supports costs and loads, including details of allocation and functionalization. All references to the Commission's Accounts are the Commission's Uniform System of Accounts as of July 1, 2006, or as amended by subsequent Commission actions. The costs includable in the attached schedules are those includable by reason of the definitions in the Commission's Accounts. If the Commission's Accounts are later revised or renumbered, any changes will be incorporated into Appendix 1 by reference, except to the extent Bonneville determines that a particular change results in a change in the type of costs allowable for Residential Exchange Program purposes. In that event, Bonneville will address the changes, including escalation rules, in its review process for the following Exchange Period.

(g) Bonneville may require a utility to account for all transactions with affiliated entities as though the affiliated entities were owned in whole or in part by the utility, if necessary, to properly determine and/or functionalize the utility's costs.

(h) A utility operating in more than one Pacific Northwest Jurisdiction must file one Appendix 1.

(i)(1) A utility operating in jurisdictions outside the Pacific Northwest Jurisdiction must allocate its total system costs among its jurisdictions within the Pacific Northwest and outside the Pacific Northwest in accord with the same allocation methods and procedures used by the Regulatory Body(ies) to establish jurisdictional costs and resulting revenue requirements. The utility's Appendix 1 filing must include details of the allocation.

(2) The allocation must exclude all costs of additional resources used to meet loads outside the region, as required by section 5(c)(7) of the Northwest Power Act. All schedule entries and supporting data must be in accord with Generally Accepted Accounting Principles and Practices as these principles and practices apply to the electric utility industry.

(j) A utility must file an attestation statement with each Appendix 1 filing and supporting documentation for each Review Period.

§ 301.9 **Functionalization of Average System Cost methodology.**

(a) Functionalization of each account included in a utility's ASC must be according to the functionalization prescribed in Table 1, Functionalization and Escalation Codes. Direct analysis on an account may be performed only if Table 1 states specifically that a utility may perform a direct analysis on the account with the exception of conservation costs. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the Account in which they are recorded. The direct analysis must be consistent with the directions provided in this section.

(b) The functionalization codes are:

(1) DIRECT – Direct Analysis.

(2) PROD – Production.

(3) TRANS – Transmission.

(4) DIST – Distribution/Other.

(5) PTD – Production, Transmission, Distribution/Other Ratio.

(6) TD – Transmission, Distribution/Other Ratio.

(7) GP – General Plant Ratio.

(8) GPM – General Plant Maintenance Ratio.

(9) PTDG – Production, Transmission, Distribution/Other, General Plant Ratio.

(10) LABOR – Labor Ratio.

(c) <u>Functionalization process</u>.

(1) Functionalization of certain accounts may be based on direct analysis or with a default ratio associated with that specific account as shown in Table 1. Once a utility uses a specific functionalization method for an account, the utility may not change the functionalization for that account without prior written approval from Bonneville.

(2) The utility must submit with its Appendix 1 all work papers, documents, or other materials that demonstrate that the functionalization under its direct analysis assigns costs based upon the actual and/or intended functional use of those items. Failure to submit the documentation will result in the entire

account being functionalized to Distribution/Other, or Production, or Transmission, as appropriate.

(d) Functionalization methods.

(1) Direct analysis, if allowed or required by Table 1, assigns costs to the Production, Transmission, and/or Distribution function of the utility. The only exception to this requirement is for conservation-related costs. Utilities will be able to identify and functionalize to Production any conservation-related costs, irrespective of the Account in which they are recorded. The analysis is subject to Bonneville review and approval. Once a utility uses a specific functionalization method for an Account, the utility may not change the functionalization for that Account without prior written approval from Bonneville.

(2) Bonneville will not allow utilities to use a combination of direct analysis and a prescribed functionalization method for the same Account. The utilities can develop and use a functionalization ratio, or use a prescribed functionalization method if the utility through direct accounts can justify how the ratio reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio.

(3) Utilities that wish to include advertising and promotion costs related to conservation will use direct analysis. If a utility records conservation costs in an Account that is normally functionalized to Distribution/Other, the utility will identify and document the conservation-related costs included in the Account, and the balance of the costs will be functionalized to Distribution/Other. The presence

of conservation-related costs in an Account does not authorize the utility to perform a direct analysis on the entire Account. This option allows a utility to assign costs in the specified Account to Production, Transmission and/or Distribution/Other based on analysis and support from the utility that demonstrates the cost assignment is appropriate. The utility must submit with its ASC filing all work papers, documents, and other materials that demonstrate the functionalization contained in its direct analysis and assigns costs based upon the actual and/or intended functional use of those items. Failure to submit the documentation will result in the entire account being functionalized to Distribution/Other for all schedules with the exception of items included in Schedule 3B, Other Included Items, where certain accounts must be functionalized to Production as appropriate.

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Schedule 1: Plant Investment/Rate Base				
Intangible Plant:				
Intangible Plant - Organization	301	DIST		CONSTANT
Intangible Plant - Franchises and Consents	302	DIRECT	PTD	CONSTANT
Intangible Plant - Miscellaneous	303	DIRECT	DIST	CONSTANT
Production Plant:				
Steam Production	310-317	PROD		CONSTANT
Nuclear Production	320-326	PROD		CONSTANT
Hydraulic Production	330-337	PROD		CONSTANT
Other Production	340-347	PROD		CONSTANT
Transmission Plant:				
Transmission Plant	350-359.1	TRANS		CONSTANT
Distribution Plant:				
Distribution Plant	360-374	DIST		CD
General Plant:				
Land and Land Rights	389	PTD		CONSTANT
Structures and Improvements	390	PTD		CONSTANT
Furniture and Equipment	391	LABOR		CONSTANT
Transportation Equipment	392	TD		CONSTANT
Stores Equipment	393	PTD		CONSTANT
Tools, Shop and Garage Equipment	394	PTD		CONSTANT
Laboratory Equipment	395	PTD		CONSTANT
Power Operated Equipment	396	TD		CONSTANT
Communication Equipment	397	PTD		CONSTANT
Miscellaneous Equipment	398	PTD		CONSTANT
Other Tangible Property	399	DIRECT	PTD	CONSTANT
Asset Retirement Costs for General Plant	399.1	PTD		CONSTANT
Depreciation Reserve:				
Steam Production Plant	108	PROD		CONSTANT
Nuclear Production Plant	108	PROD		CONSTANT
Hydraulic Production Plant	108	PROD		CONSTANT
Other Production Plant	108	PROD		CONSTANT
Transmission Plant	108	TRANS		CONSTANT
Distribution Plant	108	DIST		CONSTANT
General Plant	108	GP		CONSTANT
Amortization of Intangible Plant - Account 301	111	DIST		CONSTANT
Amortization of Intangible Plant - Account 302	111	DIRECT	PTD	CONSTANT
Amortization of Intangible Plant - Account 303	111	DIRECT	DIST	CONSTANT
Mining Plant Depreciation	108	PROD		CONSTANT
Amortization of Plant Held for Future Use	111	DIST		CONSTANT
Capital Lease - Common Plant	108	DIRECT	PTD	CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Leasehold Improvements	108	DIRECT	DIST	CONSTANT
In-Service: Depreciation of Common Plant	108	DIRECT	PTD	CONSTANT
Amortization of Other Utility Plant	108	DIRECT	DIST	CONSTANT
Amortization of Acquisition Adjustments	115	DIRECT	DIST	CONSTANT
Depreciation and Amortization Reserve (Other)		DIRECT	N/A	CONSTANT
Cash Working Capital:				
(Utility Plant) Held For Future Use	105	DIST		CONSTANT
(Utility Plant) Completed Construction - Not Classified	106	PTD		CONSTANT
Nuclear Fuel	120.2-120.6	PROD		NFUEL
Construction Work in Progress (CWIP)	107&120.1	DIST		CONSTANT
Common Plant		DIRECT	N/A	CONSTANT
Acquisition Adjustments (Electric)	114	DIRECT	DIST	CONSTANT
Other Property and Investments:				
Investment in Associated Companies	123.1	DIRECT	DIST	CONSTANT
Other Investment	124	DIST		CONSTANT
Long-Term Portion of Derivative Assets	175	DIST		CONSTANT
Long-Term Portion of Derivative Assets - Hedges	176	DIST		CONSTANT
Current and Accrued Assets:				
Fuel Stock	151	PROD		COAL
Fuel Stock Expenses Undistributed	152	PROD		CONSTANT
Plant Materials and Operating Supplies	154	PTD		INF
Merchandise (Major Only)	155	DIST		INF
Other Materials and Supplies (Major only)	156	DIST		INF
EPA Allowance Inventory	158.1	PROD		CONSTANT
EPA Allowances Withheld	158.2	PROD		CONSTANT
Stores Expense Undistributed	163	PTD		INF
Prepayments	165	PTD		CONSTANT
Derivative Instrument Assets	175	DIST		CONSTANT
Less: Long-Term Portion of Derivative Assets	175	DIST		CONSTANT
Derivative Instrument Assets – Hedges	176	DIST		CONSTANT
Less: Long-Term Portion of Derivative Assets - Hedges	176	DIST		CONSTANT
Deferred Debits:				
Unamortized Debt Expenses	181	PTDG		CONSTANT
Extraordinary Property Losses	182.1	DIRECT	DIST	CONSTANT
Unrecovered Plant and Regulatory Study Costs	182.2	DIRECT	DIST	CONSTANT
Other Regulatory Assets	182.3	DIRECT	DIST	CONSTANT
Preliminary Survey and Investigation Charges (Electric)	183	DIST		CONSTANT
Preliminary Natural Gas Survey and Investigation Charges	183.1	DIST		CONSTANT
Other Preliminary Survey and Investigation Charges	183.2	DIST		CONSTANT
Clearing Accounts	184	DIST		CONSTANT
Temporary Facilities	185	PTDG		CONSTANT
Miscellaneous Deferred Debits	186	DIRECT	DIST	CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Deferred Losses from Disposition of Utility Plant	187	DIRECT	N/A	CONSTANT
Research, Development, and Demonstration Expenditures	188	DIST		CONSTANT
Unamortized Loss on Reacquired Debt	189	PTDG		CONSTANT
Accumulated Deferred Income Taxes	190	DIST		CONSTANT
Liabilities and Other Credits (Comparative Balance Sheet):				
Derivative Instrument Liabilities	244	DIST		CONSTANT
Less: Long-Term Portion of Derivative Instrument Liabilities	244	DIST		CONSTANT
Derivative Instrument Liabilities – Hedges	245	DIST		CONSTANT
Less: Long-Term Portion of Derivative Inst Liabilities–Hedges	245	DIST		CONSTANT
Customer Advances for Construction	252	DIST		CONSTANT
Other Deferred Credits	253	DIRECT	DIST	CONSTANT
Other Regulatory Liabilities	254	DIRECT	DIST	CONSTANT
Accumulated Deferred Investment Tax Credits	255	DIST		CONSTANT
Deferred Gains from Disposition of Utility Plant	256	DIRECT	N/A	CONSTANT
Unamortized Gain on Reacquired Debt	257	PTDG		CONSTANT
Accumulated Deferred Income Taxes-Accel. Amort.	281	DIST		CONSTANT
Accumulated Deferred Income Taxes-Property	282	DIST		CONSTANT
Accumulated Deferred Income Taxes-Other	283	DIST		CONSTANT
Schedule 3: Expenses				
Power Production Expenses:				
Steam Power Generation				
Steam Power – Fuel	501	PROD		COAL
Steam Power - Operations (Excluding 501 - Fuel)	500-509	PROD		SOPS
Steam Power – Maintenance	510-515	PROD		SMN
Nuclear Power Generation				
Nuclear – Fuel	518	PROD		NFUEL
Nuclear - Operation (Excluding 518 - Fuel)	517-525	PROD		NOPS
Nuclear – Maintenance	528-532	PROD		NMN
Hydraulic Power Generation				
Hydraulic – Operation	535-540.1	PROD		HOPS
Hydraulic – Maintenance	541-545.1	PROD		HMN
Other Power Generation				
Other Power – Fuel	547	PROD		NATGAS
Other Power - Operations (Excluding 547 - Fuel)	546-550.1	PROD		OOPS
Other Power – Maintenance	551-554.1	PROD		OMN
Other Power Supply Expenses				
Purchased Power (Excluding REP Reversal)	555	PROD		CONSTANT
System Control and Load Dispatching	556	PROD		CONSTANT
Other Expenses	557	PROD		CONSTANT
BPA REP Reversal	555	PROD		CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Public Purpose Charges		DIRECT		CONSTANT
Transmission Expenses:				
Transmission of Electricity by Others (Wheeling)	565	TRANS		INF
Total Operations less Wheeling	560-567.1	TRANS		TOPS
Total Maintenance	568-574	TRANS		TMN
Distribution Expense:				
Total Operations	580-589	DIST		DOPS
Total Maintenance	590-598	DIST		DMN
Customer and Sales Expenses:				
Total Customer Accounts	901-905	DIST		CACNT
Customer Service and Information	906-907	DIST		CSERV
Customer assistance expenses (Major only)	908	DIRECT	N/A	CSERV
Customer Service and Information	909-910	DIST		CSALES
Total Sales Expense	911-917	DIST		CSALES
Administration and General Expense:				
Operation				
Administration and General Salaries	920	LABOR		A&G
Office Supplies & Expenses	921	LABOR		A&G
(Less) Administration Expenses Transferred - Credit	922	LABOR		A&G
Outside Services Employed	923	LABOR		A&G
Property Insurance	924	PTDG		A&G
Injuries and Damages	925	LABOR		A&G
Employee Pensions & Benefits	926	LABOR		A&G
Franchise Requirements	927	DIST		A&G
Regulatory Commission Expenses	928	DIST		A&G
(Less) Duplicate Charges - Credit	929	PTDG		A&G
General Advertising Expenses	930.1	DIRECT	DIST	A&G
Miscellaneous General Expenses	930.2	DIST		A&G
Rents	931	DIST		A&G
Transportation Expenses (Non Major)	933	DIST		A&G
Maintenance				
Maintenance of General Plant	935	GPM		A&G
Depreciation and Amortization:				
Amortization of Intangible Plant - Account 301	404	DIST		CONSTANT
Amortization of Intangible Plant - Account 302	404	DIRECT	PTD	CONSTANT
Amortization of Intangible Plant - Account 303	404	DIRECT	DIST	CONSTANT
Steam Production Plant	403	PROD		CONSTANT
Nuclear Production Plant	403	PROD		CONSTANT
Hydraulic Production Plant - Conventional	403	PROD		CONSTANT
Hydraulic Production Plant - Pumped Storage	403	PROD		CONSTANT
Other Production Plant	403	PROD		CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Transmission Plant	403	TRANS		CONSTANT
Distribution Plant	403	DIST		CONSTANT
General Plant	403	GP		CONSTANT
Common Plant - Electric	403 & 404	DIRECT	N/A	CONSTANT
Depreciation Expense for Asset Retirement Costs	403.1	DIRECT	N/A	CONSTANT
Amortization of Limited Term Electric Plant	404	DIRECT	N/A	CONSTANT
Amortization of Plant Acquisition Adjustments (Electric)	406	DIRECT	N/A	CONSTANT
Schedule 3A: Taxes				
FEDERAL:				
Income Tax (Included on Schedule 2)	409.1	DIST		CONSTANT
Employment Tax	408.1	LABOR		WAGES
Other Federal Taxes	408.1	DIST		CONSTANT
STATE AND OTHER:				
Property (or In-Lieu)	408.1	PTDG		CONSTANT
Unemployment	408.1	LABOR		WAGES
State Income, B&O, etc.	409.1	DIST		CONSTANT
Franchise Fees	408.1	DIST		CONSTANT
Regulatory Commission	408.1	DIST		CONSTANT
City/Municipal	408.1	DIST		CONSTANT
Other	408.1	DIST		CONSTANT
Schedule 3B: Other Included Items				
Other Included Items:				
Regulatory Debits	407.3	DIRECT	DIST	CONSTANT
Regulatory Credits	407.4	DIRECT	PROD	CONSTANT
Gain from Disposition of Utility Plant	411.6	DIRECT	PROD	CONSTANT
Loss from Disposition of Utility Plant	411.7	DIRECT	DIST	CONSTANT
Gain from Disposition of Allowances	411.8	PROD		CONSTANT
Loss from Disposition of Allowances	411.9	PROD		CONSTANT
Miscellaneous Nonoperating Income	421	DIRECT	PROD	CONSTANT
Sale for Resale:				
Sales for Resale	447	PROD		CONSTANT
Other Revenues:				
Forfeited Discounts	450	DIST		CONSTANT
Miscellaneous Service Revenues	451	DIST		CONSTANT
Sales of Water and Water Power	453	PROD		CONSTANT
Rent from Electric Property	454	TD		CONSTANT
Interdepartmental Rents	455	DIST		CONSTANT
Other Electric Revenues	456	DIRECT	PROD	CONSTANT
Revenues from Transmission of Electricity of Others	456.1	TRANS		CONSTANT
Labor Ratios				
Labor Ratio Input:				
Production		PROD		WAGES

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Transmission		TRANS		WAGES
Distribution		DIST		WAGES
Customer Accounts		DIST		WAGES
Customer Service and Informational		DIST		WAGES
Sales		DIST		WAGES
Administrative & General		PTD		WAGES

Appendix 1
ASC Utility Filing Template

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST			-	-	-
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD		-	-	-
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST		-	-	-
Total Intangible Plant					$ -	$ -	$ -	$ -
Production Plant:								
Steam Production	204-207	310-317	PROD			-	-	-
Nuclear Production	204-207	320-326	PROD			-	-	-
Hydraulic Production	204-207	330-337	PROD			-	-	-
Other Production	204-207	340-347	PROD			-	-	-
Total Production Plant					$ -	$ -	$ -	$ -
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS			-	-	-
Total Transmission Plant					$ -	$ -	$ -	$ -
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST			-	-	-
Total Distribution Plant					$ -	$ -	$ -	$ -
General Plant:								
Land and Land Rights	204-207	389	PTD			-	-	-
Structures and Improvements	204-207	390	PTD			-	-	-
Furniture and Equipment	204-207	391	LABOR			-	-	-
Transportation Equipment	204-207	392	TD			-	-	-
Stores Equipment	204-207	393	PTD			-	-	-
Tools and Garage Equipment	204-207	394	PTD			-	-	-
Laboratory Equipment	204-207	395	PTD			-	-	-
Power Operated Equipment	204-207	396	TD			-	-	-
Communication Equipment	204-207	397	PTD			-	-	-
Miscellaneous Equipment	204-207	398	PTD			-	-	-
Other Tangible Property	204-207	399	DIRECT	PTD		-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD			-		-
Total General Plant					$ -	$ -	$ -	$ -
Total Electric Plant In-Service *(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD			-	-	-
Nuclear Production Plant	219	108	PROD			-	-	-
Hydraulic Production Plant	219	108	PROD			-	-	-
Other Production Plant	219	108	PROD			-	-	-
Transmission Plant (i)	219	108	TRANS			-	-	-
Distribution Plant	219	108	DIST			-	-	-
General Plant	219	108	GP			-	-	-
Amortization of Intangible Plant - Account 301	219	111	DIST			-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST		-	-	-
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT	PTD		-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT	PTD		-	-	-
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST		-	-	-
Amortization of Acquisition Adjustments	200-201	115	DIRECT	DIST		-	-	-
Depreciation and Amortization Reserve (Other)			DIRECT					
Total Depreciation and Amortization Reserve					$ -	$ -	$ -	$ -
Total Net Plant *(Total Electric Plant In-Service) - (Total Depreciation & Amortization)*					$ -	$ -	$ -	$ -

[redacted]

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation							
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST			-	-	-
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD			-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST			-	-	-
Common Plant	356 & 356.1		DIRECT					
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST		-	-	-
Total					$ -	$ -	$ -	$ -
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST		-	-	-
Other Investment	110-111	124	DIST			-	-	-
Long-Term Portion of Derivative Assets	110-111	175	DIST			-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD			-	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD			-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD			-	-	-
Merchandise (Major Only)	110-112	155	DIST			-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST			-	-	-
EPA Allowance Inventory	110-112	158.1	PROD			-	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD			-	-	-
Prepayments	110-111	165	PTD			-	-	-
Derivative Instrument Assets	110-111	175	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST			-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST			-	-	-
Total					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG			-	-	-
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST		-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST		-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST		-	-	-
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST			-	-	-
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST			-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST			-	-	-
Clearing Accounts	110-111	184	DIST			-	-	-
Temporary Facilities	110-111	185	PTDG			-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST		-	-	-
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT					
Research, Development, and Demonstration Expenditures	110-111	188	DIST			-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG			-	-	-
Accumulated Deferred Income Taxes	110-111	190	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
<u>Total Assets and Other Debits</u>					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
Current and Accrued Liabilites								
Derivative Instrument Liabilities	112-113	244	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST			-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Deferred Credits								
Customer Advances for Construction	112-113	252	DIST			-	-	-
Other Deferred Credits	112-113	253	DIRECT	DIST		-	-	-
Other Regulatory Liabilities	112-113	254	DIRECT	DIST		-	-	-
Accumulated Deferred Investment Tax Credits	112-113	255	DIST			-	-	-
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT					
Unamortized Gain on Reacquired Debt	112-113	257	PTDG			-	-	-
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST			-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST			-	-	-
Accumulated Deferred Income Taxes-Other	112-113	283	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Total Liabilities and Other Credits					$ -	$ -	$ -	$ -
Total Rate Base					$ -	$ -	$ -	$ -

Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 1A: Cash Working Capital (f)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	-	-	-	-
Total Transmission O&M (i)	-	-	-	-
Total Distribution O&M	-	-	-	-
Total Customer & Sales	-	-	-	-
Total Administrative and General O&M	-	-	-	-
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	-	-	-	-
Revised Total O&M Expenses	$ -	$ -	$ -	$ -
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 2: Capital Structure and Rate of Return (b)

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:

Multi-Jurisdiction Investor-Owned Utility Return Calculation:

Consumer-Owned Utility Return Calculation:

Rate of Return :

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2

Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	Amount	Percent	Embedded	Weighted
Debt				
Preferred Equity				
Common Equity				
Weighted Cost of Capital	$ -			-

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) 35%

Federal Income Tax Factor

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base *(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*				

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 1

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	Amount	Percent	Embedded	Weighted	Allocation	Weighted	State Allocation
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 2

Component	Amount	Percent	Embedded	Weighted			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 3

Component	Amount	Percent	Embedded	Weighted			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Jurisdiction	Rate Base	Weighted cost	%	Weighted Return		
Total						

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation *(continued)*

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	35%	
Federal Income Tax Factor *{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*		
Federal Income Tax Adjusted Weighted Cost of Capital *(Weighted Cost of Capital Plus Federal Income Tax Factor)*		

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base *(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*				

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 2: Capital Structure and Rate of Return (b)

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	$ -				$ -

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Weighted Cost of Debt				
Return on Rate Base				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD			-	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD			-	-	-
Steam Power - Maintenance	320-323	510-515	PROD			-	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD			-	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD			-	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD			-	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD			-	-	-
Other Power - Maintenance	320-323	551-554.1	PROD			-	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	326	555	PROD		0	-	-	-
System Control and Load Dispatching	320-323	556	PROD			-	-	-
Other Expenses	320-323	557	PROD			-	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (a) (h)			DIRECT					
Total Production Expense					$ -	$ -	$ -	$ -
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS			-	-	-
Total Operations less Wheeling	320-323	560-567.1	TRANS			-	-	-
Total Maintenance	320-323	568-574	TRANS			-	-	-
Total Transmission Expense					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST			-	-	-
Total Maintenance	320-323	590-598	DIST			-	-	-
Total Distribution Expense					$ -	$ -	$ -	$ -
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST			-	-	-
Customer Service and Information	320-323	906-907	DIST			-	-	-
Customer Assistance Expenses (Major only)	320-323	908	DIRECT					
Customer Service and Information	320-323	909-910	DIST			-	-	-
Total Sales Expense	320-323	911-917	DIST			-	-	-
Total Customer and Sales Expenses					$ -	$ -	$ -	$ -
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR			-	-	-
Office Supplies & Expenses	320-323	921	LABOR			-	-	-
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR			-	-	-
Outside Services Employed (g)	320-323	923	LABOR			-	-	-
Property Insurance	320-323	924	PTDG			-	-	-
Injuries and Damages	320-323	925	LABOR			-	-	-
Employee Pensions & Benefits	320-323	926	LABOR			-	-	-
Franchise Requirements	320-323	927	DIST			-	-	-
Regulatory Commission Expenses	320-323	928	DIST			-	-	-
(Less) Duplicate Charges - Credit	320-323	929	PTDG			-	-	-
General Advertising Expenses (g)	320-323	930.1	DIST	DIST		-	-	-
Miscellaneous General Expenses	320-323	930.2	DIST			-	-	-
Rents	320-323	931	DIST			-	-	-
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM			-	-	-
Total Administration and General Expenses					$ [illegible]	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Total Operations and Maintenance					$ -	$ -	$ -	$ -
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST		-	-	-
Steam Production Plant	336	403	PROD			-	-	-
Nuclear Production Plant	336	403	PROD			-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD			-	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD			-	-	-
Other Production Plant	336	403	PROD			-	-	-
Transmission Plant (i)	336	403	TRANS			-	-	-
Distribution Plant	336	403	DIST			-	-	-
General Plant	336	403	GP			-	-	-
Common Plant - Electric	336	403	DIRECT					
Common Plant - Electric	336	404	DIRECT					
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT					
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIRECT					
Total Depreciation and Amortization					$ -	$ -	$ -	$ -
Total Operating Expenses					$ -	$ -	$ -	$ -
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINSTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:

End of Year Report Period:

ASC Filing Date:

FERC Form 1		Purchased Power - Base Period		Purchased Power - Base Period Minus 1		Purchased Power - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	326-327						
LF	326-327						
IF	326-327						
SF	326-327						
LU	326-327						
IU	326-327						
OS	326-327						
EX	326-327						
NA	326-327						
AD	326-327						
TOTAL		$ -	-	$ -	-	$ -	-

FERC Form 1		Sales for Resale - Base Period		Sales for Resale - Base Period Minus 1		Sales for Resale - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	310-311						
LF	310-311						
IF	310-311						
SF	310-311						
LU	310-311						
IU	310-311						
OS	310-311						
EX	310-311						
NA	310-311						
AD	310-311						
TOTAL		$ -	-	$ -	-	$ -	-

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 3A Items: Taxes

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Funct. Method	Total	Production	Transmission	Distribution/ Other
FEDERAL							
Income Tax	262	409.1	DIST		-	-	-
Employment Tax	262	408.1	LABOR		-	-	-
Other Federal Taxes	262	408.1	DIST		-	-	-
TOTAL FEDERAL				$ -	$ -	$ -	$ -
STATE AND OTHER							
Property or In-Lieu (c)	262	408.1	PTDG		-	-	-
Unemployment	262	408.1	LABOR		-	-	-
State Income, B&O, etc.	262	409.1	DIST		-	-	-
Franchise Fees	262	408.1	DIST		-	-	-
Regulatory Commission	262	408.1	DIST		-	-	-
City/Municipal	262	408.1	DIST		-	-	-
Other	262	408.1	DIST		-	-	-
TOTAL STATE AND OTHER TAXES				$ -	$ -	$ -	$ -
TOTAL TAXES				$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3B Other Included Items (j)

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD		-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST		-	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD		-	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD			-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD		-	-	-
Total Other Included Items					$ -	$ -	$ -	$ -
Sales for Resale:								
Sales for Resale	310	447	PROD			-	-	-
Total Sales for Resale					$ -	$ -	$ -	$ -
Other Revenues:								
Forfeited Discounts	300	450	DIST			-	-	-
Miscellaneous Service Revenues	300	451	DIST			-	-	-
Sales of Water and Water Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD			-	-	-
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD		-	-	-
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS			-	-	-
Total Other Revenues					$ -	$ -	$ -	$ -
Total Other Included Items *(Total Other + Total Sales for Resale + Total Other Revenue)*					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses *(From Schedule 3)*	$	$	$	$
Federal Income Tax Adjusted Return on Rate Base *(From Schedule 2)*	$	$	$	$
State and Other Taxes *(From Schedule 3a)*	$	$	$	$
Total Other Included Items *(From Schedule 3b)*	$	$	$	$
Total Cost *(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*	$	$	$	$

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 4: Average System Cost

Contract System Cost	
Production	$ -
Transmission	$ -
(Less) New Large Single Load Costs (d)	
Total Contract System Cost	**$ -**
Contract System Load (MWh)	
Total Retail Load	
(Less) New Large Single Load	
Total Retail Load (Net of NLSL) (d)	0
Distribution Loss (e)	0
Total Contract System Load	**0**
Average System Cost $/MWh	**$0**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	
Transmission	354-355	
Distribution	354-355	
Customer Accounts	354-355	
Customer Service and Information	354-355	
Sales	354-355	
Administrative and General	354-355	
TOTAL Operation		$0
Maintenance		
Production	354-355	
Transmission	354-355	
Distribution	354-355	
Administrative and General	354-355	
TOTAL Maintenance		$0
Operation and Maintenance		
Production (Total of lines 16 and 26)	354-355	0
Transmission (Total of lines 17 and 27)	354-355	0
Distribution (Total of lines 18 and 28)	354-355	0
Customer Accounts (From line 20)	354-355	0
Customer Service and Information (From line 20)	354-355	0
Sales (From line 21)	354-355	0
Administrative and General (Total of lines 22 and 29)	354-355	0
TOTAL Operation and Maintenance		$0

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Ratio Table

Labor Ratio Input:

	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ -	$ -	$ -	$ -
Transmission	TRANS	-	-	-	-
Distribution	DIST	-	-	-	-
Customer Accounts	DIST	-	-	-	-
Customer Service and Informational	DIST	-	-	-	-
Sales	DIST	-	-	-	-
Administrative & General	PTD	-	-	-	-
Total Labor		$ -	$ -	$ -	$ -
LABOR RATIO		**0%**	**0%**	**0%**	**0%**

GP **General Plant Ratio**	Ratio Used	Total	Production	Transmission	Distribution
Land and Land Rights	PTD	$ -	$ -	$ -	$ -
Structures and Improvements	PTD	-	-	-	-
Furniture and Equipment	LABOR	-	-	-	-
Transportation Equipment	TD	-	-	-	-
Stores Equipment	PTD	-	-	-	-
Tools and Garage Equipment	PTD	-	-	-	-
Laboratory Equipment	PTD	-	-	-	-
Power Operated Equipment	TD	-	-	-	-
Communication Equipment	PTD	-	-	-	-
Miscellaneous Equipment	PTD	-	-	-	-
Other Tangible Property	DIRECT	-	-	-	-
Asset Retirement Costs for General Plant	PTD	-	-	-	-
TOTAL		$ -	$ -	$ -	$ -
GP RATIO		**0%**	**0%**	**0%**	**0%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Ratio Table

PTD — **Production, Transmission, Distribution Ratio**

	Ratio Used	Total	Production	Transmission	Distribution
Steam Production	PROD	$ -	$ -	$ -	$ -
Nuclear Production	PROD	-	-	-	-
Hydraulic Production	PROD	-	-	-	-
Other Production	PROD	-	-	-	-
Total Production Plant		-	-	-	-
Transmission Plant	TRANS	-	-	-	-
Total Distribution Plant	DIST	-	-	-	-
TOTAL		$ -	$ -	$ -	$ -
PTD RATIO		**0%**	**0%**	**0%**	**0%**

PTDG — **Production, Transmission, Distribution and General Plant Rati**

	Ratio Used	Total	Production	Transmission	Distribution
PTD Total		$ -	$ -	$ -	$ -
Intangible Plant - Organization	DIST	-	-	-	-
Intangible Plant - Franchises and Consents	DIRECT	-	-	-	-
Intangible Plant - Miscellaneous	DIRECT	-	-	-	-
General Plant Total		-	-	-	-
TOTAL		$ -	$ -	$ -	$ -
PTDG RATIO		**0%**	**0%**	**0%**	**0%**

TD — **Transmission and Distribution Plant Ratio**

	Ratio Used	Total	Production	Transmission	Distribution
Total Transmission Plant	TRANS	$ -	$ -	$ -	$ -
Total Distribution Plant	DIST	-	-	-	-
TOTAL		$ -	$ -	$ -	$ -
TD RATIO		**0%**	**0%**	**0%**	**0%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Ratio Table

GPM

Maintenance of General Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
Structures and Improvements	PTD	$ -	$ -	$ -	$ -
Furniture and Equipment	LABOR	-	-	-	-
Communication Equipment	PTD	-	-	-	-
Miscellaneous Equipment	PTD	-	-	-	-
TOTAL		$ -	$ -	$ -	$ -
GPM RATIO		0%	0%	0%	0%

SUMMARY RATIO TABLE

Direct to Distribution	DIST	0.00%	0.00%	100.00%
Direct to Production	PROD	100.00%	0.00%	0.00%
Direct to Transmission	TRANS	0.00%	100.00%	0.00%
Direct Allocation	DIRECT	0.00%	0.00%	0.00%
General Plant	GP	0.00%	0.00%	0.00%
Maintenance of General Plant	GPM	0.00%	0.00%	0.00%
Labor Ratios	LABOR	0.00%	0.00%	0.00%
Production, Transmission, Distribution	PTD	0.00%	0.00%	0.00%
Production, Transmission, Distribution, General	PTDG	0.00%	0.00%	0.00%
Transmission, Distribution	TD	0.00%	0.00%	0.00%

IX. AVERAGE SYSTEM COST METHODOLOGY APPENDIX 1 ENDNOTES

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

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

The ROE used in the WCC calculation will then be grossed up for Federal income taxes at the marginal Federal income tax rate using the following formula to determine the percentage increase in the ROE used for ASC determination:
FIT Adder = {(WCC – (Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1-Federal Tax Rate)}

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

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

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

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

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

2) In the amount that NLSLs are not served by dedicated resources, at BPA's New Resources (NR) rates as established from time to time pursuant to section 7(f) of the Northwest Power Act, and as applicable to the Utility, and applicable BPA transmission charges if transmission costs are excluded in the determination of BPA's NR rate, to the extent such costs are recovered by the Utility's retail rates in the applicable Jurisdiction; and

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

The above three paragraphs shall determine the Base Period cost of resources used to serve NLSLs. BPA will escalate the Base Period cost of resources used to serve NLSLs to the Exchange Period using the following steps:

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

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

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

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

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

e/ The losses 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.

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.

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

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

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

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

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

Appendix 2
Chief Financial Officer Attestation

Exhibit A:
Statement of Review and Compilation of Work Performed

Appendix 2
Chief Financial Officer Attestation

<<Customer's Name>>
Average System Cost Filing
For the Base Period Beginning ______________, 20XX
And Ending ______________, 20XX

I, ____, having reviewed the Average System Cost (ASC) Appendix 1 Filing (ASC Filing) attached with this attestation, and in accordance with Exhibit A, *Statement of Review and Compilation of Work Performed*, of this Appendix 2, hereby certify that:

1. The ASC Filing has been prepared in accordance with Bonneville Power Administration's current ASC Methodology.

2. The ASC Filing excludes the costs associated with: (a) the cost of additional resources in an amount sufficient to serve any New Large Single Load after September 1, 1979; (b) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980; and (c) any costs of any generating facility which is terminated prior to initial commercial operation.

3. Based on my knowledge as <<Customer's Name>>'s Chief Financial Officer, the ASC Filing is based on <<Customer's Name>>'s audited financial statements, FERC Form 1 filings and/or Cost of Service Analysis (COSA), and other financial information, and fairly presents in all material respects the operating costs of the utility for ___________, 20XX through ___________, 20XX.

4. Based on my knowledge as <<Customer's Name>>'s Chief Financial Officer, the ASC Filing omits no material facts and contains no false statement regarding any material facts.

Respectfully submitted,

Chief Financial Officer
<<Customer's Name>>

Date:____________________

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Exhibit A to Appendix 2
Statement of Review and Compilation of Work Performed

<<Customer's Name>>
Cost of Service Analysis Report
for the Base Period _____________, 20XX
through _____________, 20XX

This document is intended to be used by Engineering and Consulting Firms to provide; 1) a statement of the review work that was performed to ensure the accuracy and correctness of the information contained in the COSA report, and 2) to provide an assurance statement that the information contained in the COSA report is presented fairly in all material respects. Independent accounting firms would present similar information in their COSA compilation reports. The Appendix 1 references below simply denote where the financial and load data will ultimately appear in the Appendix 1 filing.

Section 1 – Statement of the Work performed and procedures that were followed in preparing the Cost of Service Analysis (COSA).

Examples of work performed cited in the Statement of Work should include:

1. Reconciliation of (1) results of financial statement expense information with (2) data contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3).
2. Reconciliation of (1) tax expense and amounts paid in-lieu of taxes to state and local governmental bodies per the financial statement expense information with (2) the tax expense information contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3A).
3. Reconciliation of (1) revenue credits and other included items used to reduce the rates of the utility's native load customers contained in financial statement income information with (2) the information contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3B).
4. Reconciliation of (1) cash and short-term investment financial statement account information with (2) working capital data contained in the COSA report (ASC Filing, Appendix 1 - Schedule 1A).
5. Plant investment costs, accumulated depreciation on plant investments and net un-depreciated plant investment at year end date is reconciled to the plant investment information contained in the COSA report. Plant investment costs associated with New Large Single Loads; generating assets used to serve loads outside of the Pacific Northwest region; and generating facilities that were terminated prior to commercial operation should be identified in separate accounts (ASC Filing, Appendix 1 - Schedule 1).
6. Long-term debt information (date bonds issued, original issue amount, principal balance at year end date, and interest rate of each bond issued along with a

weighted average cost of long-term debt outstanding) is reconciled to the information contained in the COSA report (ASC Filing, Appendix 1 – Sch. 2).

7. Return on plant investment calculation (net plant investment per Item 3 above times the weighted average cost of long-term debt per Item 4 above) is reconciled to the information contained in the COSA report.
8. Items 1-3 and 5-7 above are aggregated to produce the total cost of service amounts (aggregate costs have to be less than the projected costs contained in the utility's rates) and divided by annual customer loads (Item 9 below) to arrive at the utility's base period ASC.
9. Annual customer load information (annual megawatt hours) per the statistical section of the annual report is reconciled to the COSA report information.
10. Description of analytical procedures performed to gain additional assurance over the COSA report information. Comparison of current year information with prior year information, trend analysis, financial ratio analysis, and comparison of customer load information by segment with prior year load information.
11. Description of additional compilation and review procedures performed in preparing the COSA information.

Section 2 – Report Assurance

Based upon the audited financial statements of <<Customer's Name>> for the year ending _____________, 20XX, along with other financial statement and utility operating information provided to us, we have reviewed <<Customer's Name>>'s COSA report for the twelve month period ending _________. Our review included sufficient compilation review procedures along with additional analytical procedures to allow us to conclude that the information contained in the COSA report is presented fairly in all material respects.

Respectfully submitted,

____________________________, <<Title>>
<<Company Name>> Auditing, Engineering or Management Consulting Firm

Date:___________________