INDEX

TESTIMONY of

WILLIAM J. DOUBLEDAY, RAYMOND D. BLIVEN, PAUL A. BRODIE,
and MICHAEL J. MACE

Witnesses for Bonneville Power Administration

SUBJECT: SECTION 7(b)(2) RATE TEST STUDY

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is William J. Doubleday. My qualifications are stated in WP-10-Q-BPA-14.

A. My name is Raymond D. Bliven. My qualifications are stated in WP-10-Q-BPA-06.

A. My name is Paul A. Brodie. My qualifications are stated in WP-10-Q-BPA-09.

A. My name is Michael J. Mace. My qualifications are stated in WP-10-Q-BPA-39.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor BPA's Section 7(b)(2) Rate Test Study (Study), WP-10-E-BPA-06, and Section 7(b)(2) Rate Test Study Documentation (Documentation), WP-10-E-BPA-06A. In addition, we are sponsoring one minor change to the *Section 7(b)(2) Implementation Methodology* (*Implementation Methodology*) and additional minor edits and clarifications to the *Implementation Methodology*, WP-10-E-BPA-06, Attachment 2.

Q. Please summarize your testimony and its organization.

A. This testimony will discuss the implementation of the rate test established by section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). Section 1 outlines the purpose of this testimony. Section 2 summarizes the section 7(b)(2) rate test and generally describes our proposal to adopt the previous implementation of the rate test for this rate period. Section 3 describes the *Implementation Methodology* and discusses proposed changes. Section 4 discusses the determination of the test period for the 7(b)(2) rate test. Section 5 discusses the financing benefits analysis performed by BPA's financial advisor, Public Financial Management (PFM), and the application of that analysis to the rate test. This is the only section of our testimony on which Mr. Mace is testifying. Section 6 discusses resource acquisitions in the 7(b)(2) Case along with changes to resource amounts and costs. Section 7 discusses the identification of non-committed resources in the 7(b)(2) Case. Section 8 discusses the treatment of conservation in the rate test. Section 9 discusses reserve benefits from the curtailment of direct-service industrial customer (DSI) loads. Section 10 discusses the changes in the model used to perform the rate test. Section 11 refers to the Average System Cost and forecast residential exchange load inputs into the rate model, as discussed in Russell et al., WP-10-E-BPA-18. Finally, Section 12 summarizes the results of the rate test.

Section 2: Section 7(b)(2) Rate Test

Q. What is the section 7(b)(2) rate test?

A. Section 7(b)(2) of the Northwest Power Act requires that after July 1, 1985, BPA will perform a rate test to ensure that the projected amounts to be charged for firm power for the combined general requirements of BPA's PF Preference customers may not exceed, in total, an amount equal to the power costs for such customers calculated using five specific assumptions that remove certain effects of the Northwest Power Act.

Q. How was the 7(b)(2) rate test performed for the Initial Proposal?

A. The rate test involves the projection and comparison of two sets of wholesale power rates for general requirements of BPA's public body, cooperative, and Federal agency customers (7(b)(2) Customers). These are: 1) a set for the rate period (FY 2010-2011) and the ensuing 4 years (FY 2012-2015) before the effects of section 7(b)(2) are incorporated (Program Case rates); and 2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) Case rates). The 7(b)(2) Case rates are modeled in the same manner as the Program Case rates except for the five assumptions listed in section 7(b)(2). The five assumptions used to model the 7(b)(2) Case are:

1) Within or adjacent DSI loads are transferred to 7(b)(2) Customers at the start of the 7(b)(2) rate test period; any remaining DSI loads are deemed transferred to non-7(b)(2) Customers and are not considered in the 7(b)(2) Case.
2) 7(b)(2) Customers are served first with Federal Base System (FBS) resources not obligated under contracts existing as of the effective date of the Northwest Power Act.
3) No section 5(c) Residential Exchange Program (REP) takes place.
4) Additional resources of three specified types serve any remaining loads of 7(b)(2) Customers when FBS resources are exhausted. These resources are contained in the 7(b)(2)(D) resource stack.
5) The reserve benefits acquired under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. Financing benefits to 7(b)(2) Customers under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. The 7(b)(2) Case power costs will reflect these increased costs to the 7(b)(2) Customers.

For a discussion of the development of the Program and 7(b)(2) Case rates, *see generally* Study, WP-10-E-BPA-06, and Documentation, WP-10-E-BPA-06A.

Q. What follows after the two sets of rates are developed?

A. Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the Program Case rates. Next, the nominal rate for each year is discounted (discount rates are based on BPA's forecast borrowing rates for the rate test period) to the beginning of the rate test period, FY 2010. The discounted Program Case rates are averaged, as are the discounted 7(b)(2) Case rates. Both averages are rounded to the nearest hundredth of a mill for comparison. Because the average Program Case rate is higher than the average 7(b)(2) Case rate, the rate test for the WP-10 Initial Proposal triggers by 8.07 mills per kilowatthour.

Q. Is the 7(b)(2) rate test generally conducted in the same manner for the Initial Proposal as it was for the WP-07 Supplemental Final Proposal?

A. Yes. Except as otherwise stated in the following sections of this testimony, we perform the section 7(b)(2) rate test in the same manner as described in our previous testimony (Keep et al., WP-07-E-BPA-68; Doubleday et al., WP-07-E-BPA-85), final studies (FY 2009 Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-14; FY 2009 Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-14A), and the WP-07 Supplemental Wholesale Power Rate Case Administrator's Final Record of Decision (WP-07-A-05, Chapter 16.0). Two other important documents that provided guidance are the *Section 7(b)(2) Legal Interpretation*, WP-07-A-06 (*Legal Interpretation*) and the *Implementation Methodology*, WP-07-A-07. We propose to implement the section 7(b)(2) rate test as described in the above-referenced materials for this rate proceeding, unless expressly modified in this testimony.

Q. Has the 7(b)(2) rate test been generally conducted in the same manner since its inception in 1984?

A. Yes. While there have been minor changes over the years, the basic interpretation of the 7(b)(2) rate test and its application have been consistently applied in determining the 7(b)(2) rate protection amount.

Q. Do you intend to repeat the discussion from the material presented in the WP-07 Supplemental rate proceeding in this testimony?

A. Generally, no. We do not intend to repeat the previous analysis or discussion regarding the section 7(b)(2) rate test in this testimony unless doing so provides context for our proposed changes.

Q. Where can parties obtain a copy of the materials that describe BPA's previous implementation of the section 7(b)(2) rate test?

A. BPA will be filing a motion with the hearing officer requesting that the material from the WP-07 Supplemental rate proceeding be incorporated into the record of this proceeding. Included in this material will be the section 7(b)(2) rate test studies, testimony, and Administrator's ROD mentioned previously. The *Legal Interpretation* and *Implementation Methodology* are provided as attachments to the Study, WP-10-E-BPA-06.

Section 3: Section 7(b)(2) Implementation Methodology

Q. What is the Section 7(b)(2) Implementation Methodology?

A. The *Implementation Methodology* is included as Attachment 2 to the Study, WP-10-E-BPA-06. The proposed changes are shown in "red-line" markup for easy identification. The *Implementation Methodology* is a document that guides BPA in performing the section 7(b)(2) rate test. It sets forth the methodologies to be used in preparing necessary inputs and describes the assumptions to be used in developing the rates to be compared in the rate test.

Q. What is the Legal Interpretation?

A. The *Legal Interpretation* is included as Attachment 1 to the Study, WP-10-E-BPA-06. The *Legal Interpretation* is a document that resolves basic legal issues involved in the implementation of section 7(b)(2) through analysis of statutory language and legislative history. The *Legal Interpretation* provides the legal foundation for the *Implementation Methodology*.

Q. Do you propose to make any changes to the Implementation Methodology?

A. Yes. We propose to make one minor change to the *Implementation Methodology* and to make additional edits and clarifications. We propose to change the mathematical rounding of the test period averages of the Program Case and 7(b)(2) Case rates. We also propose to change the 7(b)(2) rate test trigger from the nearest tenth of a mill per kilowatthour to the nearest hundredth of a mill per kilowatthour.

Q. Please describe your proposed mathematical rounding change.

A. After the annual Program Case and Section 7(b)(2) Case rates are calculated for the rate test period, the rates are discounted and averaged for each Case. The averaged rates are then rounded for comparison. The 1984 *Implementation Methodology* instructed this rounding be to the nearest tenth of a mill per kilowatthour. We are proposing to change this provision such that the average of the annual Program Case rates and the average of the annual 7(b)(2) Case rates are rounded to the nearest one hundredth of a mill per kilowatthour before comparison. In addition, we propose that if the average of the Program Case rates is higher than the average of the 7(b)(2) Case rates, the difference, known as the 7(b)(2) rate test trigger, also be expressed in one hundredth of a mill per kilowatthour increments.

Q. Why did the 1984 Implementation Methodology round the rates and the trigger to the nearest one tenth of a mill?

A. BPA chose the one-tenth of a mill level of significance to be consistent with the rounding rules used in establishing wholesale power and transmission rates at the time the 1984 *Implementation Methodology* was adopted. *See* Section 7(b)(2) Implementation Methodology Administrator’s Record of Decision, b2-84-F-02 at 32.

Q. *Why are you proposing to make this mathematical rounding change to the Implementation Methodology?*

A. The current instruction in the *Implementation Methodology* to round to the nearest tenth of a mill per kilowatthour is a holdover from the period when the *Implementation Methodology* was originally drafted in 1984. At that time, BPA's rates were calculated to the nearest tenth of a mill per kilowatthour. More recently, however, BPA's rates have been calculated to the nearest hundredth of a mill. To be consistent, we believe that the rounding provisions of the *Implementation Methodology* should be updated to conform to the way BPA develops its rates today. In addition, we found during the WP-07 Supplemental rate proceeding that small changes in costs or revenue credits included in rates were producing significant changes to the level of the power rates and REP benefits. This would result if the small change in a cost or revenue credit moved one of the average rates across a rounding boundary, *i.e.*, a $640,000 cost adjustment could change a rate from 22.05 to 22.04, thus changing the rounded rate from 22.1 to 22.0. Such changes would result in REP benefits changing about $4 million. Conversely, a $5,750,000 cost adjustment could change a rate from 22.14 to 22.06, but would not produce any change in REP benefits. Under the proposed rounding rule, the changes in costs or revenue credits would have impacts on REP benefits proportionate to the magnitude of the change. This modification to the rounding rule is not expected to materially impact the results of the rate test and will have the additional benefit of allowing BPA to more precisely calculate both the rate protection afforded PF Preference customers and the REP benefits received by exchanging utilities. We do not believe that the proposed change biases the results toward either the PF Preference customers or those receiving REP benefits. Changes due to rounding may occur just as frequently in an upward direction as a downward direction.

Q. What edits and clarifications do you propose for the Implementation Methodology?

A. In describing the Program Case in section IV, minor changes are made to improve readability.

In section V.3, the word "dedicated" is replaced with the word "committed." This change conforms the *Implementation Methodology* to the wording of section 7(b)(2)(D) of the Northwest Power Act. The word "dedicated" has certain meanings through its use in power sales contracts that may or may not agree with word "committed."

In describing Financing Benefits in the 7(b)(2) Case, the *Implementation Methodology* states: "Section 7(b)(2)(E)(1) requires that BPA assume that Quantifiable Monetary Savings to 7(b)(2) Customers resulting from reduced public utility financing costs for the first two types of non-FBS resources described above were not achieved in the 7(b)(2) Case. Therefore, any additional resources required to serve the General Requirements of 7(b)(2) Customers will not reflect the financing cost reductions implicit in resource acquisitions by public bodies." We propose to add an additional sentence stating: "Non-conservation Type 1 and Type 2 resources that are already financed and constructed and that did not receive any financing benefit associated with having a BPA acquisition contract when originally constructed or when refinanced do not have their financing costs changed by the financing study." This additional sentence is proposed in order to clarify that not all resources in the resource stack have their costs adjusted by the financing study. Those existing resources that have been built and financed in the past, where the original or subsequent refinancings did not receive the benefit of a BPA acquisition contract, would not be affected by the Financing Study.

Section 4: Test Period

Q. Please describe the determination of the rate test period for the 7(b)(2) rate test.

A. The Initial Proposal uses a two-year rate period. The *Implementation Methodology* states that the rate test period will consist of the rate period year(s) for the relevant rate case plus the ensuing four years. In developing the rates in the Initial Proposal, BPA is using FY 2010-2011 as the rate period. Therefore, we use the same rate period (FY 2010-2011) plus the ensuing four years (FY 2012-2015) as the 7(b)(2) rate test period.

Section 5: Financing Analysis

Q. What is the financing analysis?

A. Section 7(b)(2)(E) of the Northwest Power Act directs the Administrator to assume, for purposes of the rate test, that quantifiable monetary savings resulting from reduced public body and cooperative financing costs were not achieved. The financing analysis determines resource financing costs associated with different resource types identified in section 7(b)(2)(D) that are owned or purchased by 7(b)(2) Customers, evaluating the resource costs with and without a BPA acquisition contract.

Q. Was a new financing analysis performed for this rate proceeding?

A. Yes. BPA's financial advisor, Public Financial Management, prepared a new financing analysis for this proceeding. It is included in the Study, WP-10-E-BPA-06, Appendix A.

Q. Please describe the primary conclusion that can be drawn from the financing analysis.

A. The primary conclusion that can be drawn from the financing analysis is that for most types of financing there is a positive benefit from BPA providing financial backing to the resources financed in the Program Case. Financing costs are projected to be higher in the 7(b)(2) Case, where resource financings do not receive the benefit of BPA financial backing. A summary of the conclusions regarding the financing of specific resource types using different debt maturities can be found in the Study, WP-10-E-BPA-06, Appendix A, Section 3, Table A.

Q. Was the financing analysis conducted using the same methodology that was used in the WP-07 Supplemental Final Proposal?

A. Yes. Like the WP-07 Supplemental Final Proposal, the financing analysis for the Initial Proposal departs from prior financing reports by using historical interest rate averages over the past three years. Prior to the WP-07 Supplemental financing report, the interest rate assumptions were developed by averaging data over a 10-year period. The decision to continue to use the most recent three-year historical period is due to the current high level of volatility and uncertainty that exists in credit markets.

Q. How are the results of the financing analysis applied in the 7(b)(2) rate test?

A. When additional resources are needed to meet 7(b)(2) Customers' loads in the 7(b)(2) Case when such loads are in excess of the capability of FBS resources, section 7(b)(2)(D) provides that three types of resources are used in the 7(b)(2) Case resource stack to meet these loads. The first type, or "Type 1" resources, are actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case. The Type 1 resources included in the resource stack are the Cowlitz Falls Hydro Project, the Idaho Falls Hydro Project, Western Generation Agency's Wauna CoGen resource, billing credit resources, and 15 years of conservation resources. The interest rate differential of an additional 5 basis points identified in the financing analysis for the Cowlitz Falls Hydro resource is reflected in the debt service in the 7(b)(2) Case. Interest rate projections of 4.57 percent for financing the capitalized portion of conservation resources over a 15-year term and 3.79 percent for expensed conservation costs that were deferred and financed over a 5-year period were used to calculate the conservation debt service requirements in the 7(b)(2) Case.

The only “Type 2” resource (7(b)(2) Customer resources not currently committed to regional loads) in the resource stack is Power Resources Cooperative’s (PRC) 10 percent share of the Boardman Coal Plant, which is sold out of region to the Turlock Irrigation District in California. Type 1 and Type 2 non-conservation resources that are already financed and constructed, and that did not receive any financing benefit associated with having a BPA acquisition contract when originally constructed or when refinanced, do not have their financing costs changed by the financing study. “Type 3” resources (additional resources at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case) in the resource stack are not subject to the financing study because they do not meet the criterion of being owned or purchased by public bodies or cooperatives.

Section 6: Resource Acquisitions

Q. *Are 7(b)(2) Customer loads the same in the Program and 7(b)(2) Cases?*

A. No. As provided in the *Implementation Methodology*, 7(b)(2) Case customer loads are increased by the amount of actual or planned conservation included in developing the Program Case loads. In addition, the limited amount of DSI load assumed in the Program Case is to be served by 7(b)(2) Customers in the 7(b)(2) Case.

Q. *Are resources needed in addition to FBS resources to serve the 7(b)(2) Customers’ loads in the 7(b)(2) Case?*

A. Yes. Additional resources are needed to serve the 7(b)(2) Customers’ loads from the start of the test period.

Q. *How are you calculating the amount of additional resources needed to serve the 7(b)(2) Customers’ loads in the 7(b)(2) Case?*

A. The RAM2010 model conducts a load resource balance calculation in the 7(b)(2) Case for each year of the test period.

Q. *How do you determine the 7(b)(2) Case PF load forecast?*

A. The 7(b)(2) Customer load forecast for the 7(b)(2) Case begins with the PF Preference loads from the Program Case and adds load associated with conservation resource acquisitions that have not occurred in the 7(b)(2) Case. Over the test period, there is an approximately 486 aMW increase in 7(b)(2) Customer load over and above the Program Case PF Preference load due to forgone conservation and billing credit resource purchases. In addition, for purposes of ratemaking, a limited amount of load was assumed in the Program Case for within or adjacent DSIs which has increased the 7(b)(2) Customer load in the 7(b)(2) Case by 402 aMW.

Q. *How much of the assumed DSI load is within or adjacent?*

A. All current DSIs are considered within or adjacent. The three remaining DSIs are Alcoa-Ferndale, Columbia Falls Aluminum, and Port Townsend Paper. Alcoa-Ferndale is considered to be adjacent to the service area of Whatcom County PUD. Columbia Falls Aluminum is considered within the service area of Flathead Electric Cooperative, and Port Townsend Paper is considered adjacent to Clallam County PUD,

Q. *Is the predecessor to Port Townsend Paper identified in the legislative history of the Northwest Power Act?*

A. Yes. Crown Zellerbach is included in the Appendix B of the Senate report as a DSI that "Could not readily be served by BPA preference customers" at that time. However, today Port Townsend Paper is served from a power line between BPA's Fairmont substation and the mill. The line is partly owned by Clallam County PUD and partly by the mill. There is no intervening ownership or service by Puget Sound Energy, the local investor-owned utility (IOU). Therefore, because the mill is electrically interconnected to a Clallam power line, it should be considered adjacent to Clallam, even though the mill is within the service area of Puget Sound Energy.

Q. How are non-FBS resources added to serve the 7(b)(2) Case load?

A. As established in the *Implementation Methodology* and described above, three types of additional resources may be added to serve 7(b)(2) Customer loads after exhausting the FBS resources. They are Type 1, actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case; Type 2, existing 7(b)(2) Customer resources not currently committed to regional loads; and Type 3, additional needed resources at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case.

A detailed analysis of conservation resource savings and their related costs for the 7(b)(2) Case is included in Appendix D to the Study. A detailed analysis of non-conservation resource amounts (MW) and their related costs is contained in Appendix C to the Study. Type 1 and Type 2 resources are stacked together in least-cost-first order in discrete increments reflecting the actual size of the resource or the increment acquired by BPA. These resources are assumed to come on-line in the order in which they were stacked to meet the 7(b)(2) Customer loads after FBS resources are exhausted. Whenever a conservation or billing credit resource is the least-cost resource selected, the amount (aMW) of conservation or billing credit is treated as a reduction to the 7(b)(2) Customer loads, consistent with its treatment in the Program Case.

Q. Are any changes planned for the WP-10 Final Proposal and Study in the amounts or costs of Type 1 and Type 2 resources that were used in the Initial Proposal?

A. Yes. In analyzing the amounts and costs of resources that were established in the Integrated Program Review process, it was discovered that errors were made in both the amount and cost of non-conservation resources. The costs included in the 7(b)(2) resource stack are consistent with the Integrated Program Review so that the costs in the 7(b)(2) Case are consistent with the Program Case. However, the amounts and/or the costs associated with the Cowlitz Falls Hydro Project, Idaho Falls Hydro Project, and

Wauna CoGen resource will change for the Final Proposal. The annual purchased power costs and changes to the amounts will be revised as part of BPA's Integrated Program Review 2 process in Spring 2009. The anticipated changes in the amounts and costs for these resources are outlined in the resource analysis contained in Appendix C to the Study.

Section 7: Non-Committed Resources

Q. Have you identified any Type 2 resources (existing 7(b)(2) Customer resources not committed to regional loads pursuant to section 5(b) of the Northwest Power Act)?

A. Yes. Section 7(b)(2)(D)(ii) of the Northwest Power Act provides that, in addition to FBS resources, 7(b)(2) Customers' loads in the 7(b)(2) Case are met with "resources not committed to load pursuant to section 5(b)." 16 U.S.C. § 839e(b)(2)(D)(ii). BPA's *Legal Interpretation* also refers to "resources owned or purchased by the 7(b)(2) Customers, and not committed to load by public agencies and investor-owned utilities pursuant to section 5(b)." We have identified only one resource satisfying these requirements, PRC's 10 percent share of the Boardman coal plant. This resource's capability is 50 aMW.

Q. Do you propose any changes to the treatment of the Mid-Columbia resources for purposes of the section 7(b)(2) resource stack?

A. Yes. In the WP-07 Supplemental rate proceeding, small portions of Grant County PUD's Mid-Columbia resources (Wanapum and Priest Rapids hydroelectric generating plants) that were purchased by Idaho co-ops, along with the portion sold at auction, were placed in the resource stack because it could not be established that the resources were dedicated to 5(b) loads. In the instant rate proceeding, we propose to exclude all of Grant County PUD's Mid-Columbia resource capability from the 7(b)(2) resource stack.

Q. *Why do you propose to exclude all of Grant County PUD's Mid-Columbia resource capability from the 7(b)(2) resource stack?*

A. Upon further review for the Initial Proposal, we realized that the WP-07 Supplemental criteria were inadequate to firmly establish that Grant County PUD's Mid-Columbia resources in question were "not committed to load pursuant to section 5(b)." BPA's presumption that the resources were not being committed to regional loads was different from and inconsistent with the criteria used in BPA's Section 5(b)/9(c) Policy. Those criteria essentially require the resource owner, Grant County PUD, to be self-policing; that is to say, Grant was charged with ensuring that the resource was not sold outside of the region. BPA's section 9(c) determination with Grant requires that Grant's contracts for the sale of power include a provision that the power sold is not sold, resold, distributed for use, or used outside the Pacific Northwest region except in conformance with the Bonneville Project Act, 16 U.S.C. § 832; the Pacific Northwest Consumer Power Preference Act, Pub.L. 88-552; or the Northwest Power Act, 16 U.S.C. § 839. A compliance protocol was established making Grant responsible for the in-region use of the power when the sale at auction is made to an entity that does not have a Northwest Power Act section 5(b) contract with BPA or does not directly serve regional consumer loads. (*See* Grant's prototype power sales contract with restrictions on selling this purchased power outside the region and BPA's 5(b)/9(c) determination letter to Grant, which are included in the Study, WP-10-E-BPA-05, Appendix C, C–128 to C-148.) In light of this additional information, we are proposing to adopt a rebuttable presumption that sales of excess power from Grant's Mid-Columbia resources are being sold to 7(b)(2) Customers within the region. This assumption comports with the terms of Grant's contract, with BPA's Section 5(b)/9(c) Policy, and with section 7(b)(2)(D)(ii). As long as the purchaser's monthly sales of power to BPA's customers meet or exceed the amount of firm power bought at auction and delivered for the month, the resale should be considered committed to load in the region.

Q. *What is the effect of removing the 14.9 aMW of Priest Rapids generation and 14.8 aMW of Wanapum generation from the resource stack?*

A. Due to the small size of these two resources in the resource stack, the impact on the 7(b)(2) Case rate is small. The costs of these two resources have increased in recent years (Study, WP-10-E-BPA-05, Appendix C, C-101 to C-127), which has decreased the cost spread between these resources and the other resources in the stack when compared to the cost spreads that were present in prior rate cases. These resources would still have been the lowest cost resources in the resource stack and, if they had been in the stack, they would have somewhat lowered the 7(b)(2) Case rates.

Q. *Did you review and consider whether any other Mid-Columbia resources should be included in the resource stack?*

A. Yes. We reviewed the Wells Dam hydroelectric generation plant owned and operated by Douglas County PUD, and the Rocky Reach, Rock Island, and Lake Chelan hydroelectric generation plants owned and operated by Chelan County PUD. Our review concluded that purchases of the output from these facilities are meeting the firm power requirements of consumer-owned utilities (COU) and IOUs in the region and there are no portions of the generating capabilities of these plants that were available to the 7(b)(2) resource stack.

Q. *What conclusion do you reach concerning power that has been sold by Chelan County PUD to Colockum and/or Alcoa or Alcoa Power Generating Inc.?*

A. We conclude that the power sold by Chelan County PUD through its power sales contracts with Colockum and/or Alcoa, which have provided power to Alcoa's Wenatchee smelter since 1957, is serving native load of Chelan County PUD and therefore is not available to the 7(b)(2) resource stack. Even if this load were determined not to be native load of Chelan County PUD, this load is being met by Chelan County PUD throughout the rate test period and is thereby reducing the Administrator's load obligations during this period, and thus this load is not includable in the resource stack.

Q. *Apart from the Mid-Columbia resources, do you propose to change any other aspects of the 7(b)(2) resource stack?*

A. Yes. The Nine Canyon wind resource that was included in the WP-07 Supplemental 7(b)(2)(D) resource stack was removed from the resource stack based on reasoning similar to that outlined above for Grant PUD's Priest Rapids Project's two hydro resources. We assume 7(b)(2) Customers that purchased portions of the Nine Canyon wind resource are using this power as "unspecified" resources that have been declared as serving a utility's native load (both the purchaser of the resource's output and subsequent purchasers) pursuant to section 5(b) of the Northwest Power Act, which decreases BPA's load obligations. We believe this fails the requirement that the resource is "…not committed to load pursuant to section 5(b)." 16 U.S.C. § 839e(b)(2)(D)(ii). BPA and COUs must also comply with the provisions of the Bonneville Project Act, 16 U.S.C. § 832; the Pacific Northwest Consumer Power Preference Act, Pub.L. 88-552; and the Northwest Power Act, 16 U.S.C. § 839, before selling power outside the region. None of BPA's 7(b)(2) Customers that own shares of Nine Canyon's power capability has had a portion of its BPA power purchases "decremented" based upon sales of power from this resource outside the region as provided in BPA's Section 5(b)/9(c) Policy. This resource was not selected to meet 7(b)(2) Customer loads in the WP-07 Supplemental 7(b)(2) rate test, and it would not have been selected as a least-cost resource in this rate test. Thus, its exclusion from the resource stack would have had no impact on either 7(b)(2) rate test.

Section 8: Treatment Of Conservation Resources

Q. *Do you propose any changes to your treatment of conservation as a resource for purposes of the section 7(b)(2) rate test?*

A. Generally, no. We continue to treat conservation as an available resource for purposes of the section 7(b)(2) rate test. We have updated the cost and conservation savings amounts to reflect BPA's projected conservation budgets for FY 2009-2015 and for changes in load assumptions used to calculate the amount and cost of conservation available for selection in the 7(b)(2) resource stack. The amount and cost of the 2008 programmatic conservation will be revised for the Final Proposal based upon the 2008 Conservation Resource Energy Data, "the Red Book," when it is published in Spring 2009. In addition, the projected conservation savings amounts (aMW) and costs for FY 2010-2015 will be updated for changes to projected conservation budgets for FY 2010-2015 made during the IPR-2 process, which is scheduled to be conducted in Spring 2009. Conservation resources that have become obsolete by the end of the rate test period are removed from the resource stack. Beyond these limited updates, no methodological changes have been made to the treatment of conservation in performing the rate test.

Q. *Do you propose any changes to the WP-07 Supplemental Final Proposal's treatment of conservation to address the obsolescence of conservation measures?*

A. No. The life of conservation resources in the Initial Proposal is the same period of 15 years that was previously used in the WP-07 Supplemental Final Proposal. The determination of which years of programmatic conservation are available to the resource stack is based on the same methodology. For purposes of ratemaking, a programmatic conservation resource is assumed to be obsolete if its year of origin plus its expected life minus one total less than the last year of the rate test period in question, FY 2015. The expected life of a programmatic conservation resource in the 7(b)(2) Case resource stack is assumed to be equal to the time period over which the resource is amortized. After this period has passed, it is assumed the conservation for that year produces no more measurable savings. For FY 2001-2015, that time period is 15 years. Therefore, programmatic conservation resources from FY 1982 to FY 2000 have been determined to be obsolete and have been removed from consideration in the calculation of base rates for the FY 2010-2015 rate test period.

Q. *Do you propose any changes to the accounting and financing treatment of conservation in the 7(b)(2) Case?*

A. Yes. We are proposing to defer, amortize, and finance the annual expensed amounts of conservation expenditures over a 5-year period. In the WP-07 Supplemental ROD, a 7-year period was used to defer, amortize, and finance the annual expensed amounts of conservation. WP-07 Supplemental ROD, WP-07-A-05, Section 16.4.

Q. *What criteria are used to determine the period of years over which to defer, amortize, and finance the annual expensed conservation?*

A. In the WP-07 Supplemental ROD, BPA established criteria to help determine what the Joint Operating Agency (JOA) would have likely done in the 7(b)(2) Case in choosing the accounting and financing policies associated with making a large conservation investment. The WP-07 Supplemental ROD criteria were: 1) Resource Stack Composition; 2) Additional Financing Costs Associated with Deferring the First-Year Expensed Costs; 3) Number of Years Required to Recover Conservation Costs; and 4) the Cost Treatment Comparability Between the Program Case and the 7(b)(2) Case. In the Initial Proposal we propose to add a fifth criterion, 7(b)(2) Case Rate Impacts, in arriving at our decision to amortize and finance the deferred expensed conservation expenditures over a 5-year period.

Q. *Please describe the proposed 7(b)(2) Case Rate Impact criterion.*

A. This criterion would evaluate the impact of the different conservation expense financing time periods on the 7(b)(2) Case rate. The purpose of the evaluation of the five criteria is *not* to decide what the appropriate 7(b)(2) Case rate should be. The purpose of the analysis is to quantify the amount of the first year rate "spike" associated with the expense alternative and to evaluate the rate reduction benefits of the deferral alternatives, along with the other four criteria considerations, in arriving at an accounting/financing policy that would best serve the JOA and its 7(b)(2) member utilities.

Q. Why are these five criteria chosen to help determine the appropriate accounting and financing treatment used in the 7(b)(2) Case?

A. The first criterion, resource stack composition is chosen for its ability to identify the number of resources, their quantity, and their related costs that were used to meet the 7(b)(2) customer loads. This criterion establishes the degree to which conservation resources are relied upon to meet these loads and help justify the deferral treatment for conservation expenses. The fifth criterion, 7(b)(2) rate impacts, is chosen to quantify the amount of the first year rate "spike" associated with the conservation expense alternatives and to evaluate the rate reduction benefits associated with the alternatives. This alternative also provides justification for the expense deferral treatment. The other three alternatives (two, three, and four) are chosen for their ability to quantify the amount of additional interest expense, the additional time required to recover conservation costs, and the overall comparability of the amount of conservation expenses contained in the Program Case and the 7(b)(2) Case. These three criteria taken together assist in the quantification of the additional costs and the negative attributes associated with the deferral of the first-year conservation operating expenses. All of the criteria taken together allowed us to weigh the costs and benefits of the different alternatives in reaching a conclusion on the alternative that would best serve the JOA and its member utilities.

Q. *What amortization and financing alternatives are considered and analyzed for the five criteria?*

A. Capitalized conservation costs are treated in the same manner across all of the alternatives; they were financed over a period of 15 years. Several different amortization/financing periods are considered and analyzed for conservation expenditures that are operating expenses of the period (first year expenses) in the Program Case:

<u>Alternative 1</u> –Expense the operating expenses in the year incurred, just like the Program Case treatment.

<u>Alternative 2</u> – Defer the operating expenses and finance them over 4 years.

<u>Alternative 3</u> – Defer the operating expenses and finance them over 5 years.

<u>Alternative 4</u> – Defer the operating expenses and finance them over 6 years.

<u>Alternative 5</u> – Defer the operating expenses and finance them over 7 years.

<u>Alternative 6</u> – Defer the operating expenses and finance them over 15 years.

These alternatives cover the minimum (Alternative 1) and the maximum (Alternative 6) limits of expense deferment, along with the most probable range of alternatives to be considered for analysis.

Q. *What amortization and financing period do you believe is the most appropriate for the Initial Proposal?*

A. After analyzing all five decision criteria outlined above (Study, WP-10-E-BPA-06, Appendix B, Summary Analysis – Accounting /Financing Treatment of Expensed Conservation Costs, B-6 through B-11), we determined that the five-year amortization and financing period (Alternative 3) was the best choice. In making this decision, all five criteria were considered without weighting or ranking. Key conclusions from our analysis of the five factors that support this decision are the following:

1) *7(b)(2) Resource Stack Resources Chosen to Meet 7(b)(2) Customer Loads – Resource Stack Composition:* Nine out of twelve resources chosen to meet

7(b)(2) Customer loads in the first year are conservation resources (255 aMW), comprising 73 percent of the aMW needed to meet 7(b)(2) loads in the first year. The size of the first year conservation program, together with the amount of first year expensed costs of $325 million and the "spike" in the rate for FY 2010, support a decision to defer these expenditures under Statement on Financial Accounting Standards No. 71 – Accounting for the Effects on Certain Types of Regulation, as compared to choosing to expense them in the first year.

2) *Financing Cost Impacts:* The additional financing costs associated with deferring the recovery of expensed conservation costs can significantly increase the cost of conservation when a longer deferral period is chosen. The choice of a 15-year deferral and financing period would increase the cost of conservation by $312.4 million, an amount that is a 40.34 percent increase above the original expensed conservation costs. Deferring and financing conservation costs over four to seven years increases the cost of conservation from $72.9 to 127.7 million, which amounts to a 9.42 percent to 16.50 percent increase above the original expensed conservation costs. The amount of additional interest expense and the cumulative rate impacts of deferring these costs into later rate periods support the choice of a shorter deferral period.

3) *Cost Recovery:* The cost recovery analysis demonstrates that Alternative 1, with no deferral of first year conservation expenses, recovers 73.8 percent of the total costs of conservation (excluding interest) within the rate test period. Alternative 6, which defers and finances the operating expenses over 15 years, recovers only 22.3 percent of the total costs over the rate test period. Alternatives 2 through 5 recover a range of 61.5 percent to 46.0 percent of the total conservation costs over the rate test period. Alternatives 2 and 3 were the best choices to mitigate the delay in recovering expensed costs so that they could be

reinvested in additional utility plant assets or redeployed to meet the other operating needs of the utility.

4) *Comparability of Costs:* The comparability analysis compares the conservation cost treatment between the Program Case and the 7(b)(2) Case. The Program Case revenue requirement includes: 1), conservation expenses, all are expensed in the first year they are incurred; 2) the amortization expense of capitalized costs being amortized over 5 years, and 3) the interest expense component of debt service. In contrast the 7(b)(2) Case revenue requirement includes the debt service (both principal and interest) associated with the deferral of operating expenses along with the debt service (both principal and interest) of capitalized expenditures that are amortized and financed over a 15-year period. Both Cases have the same level of Planned Net Revenues for Risk (PNRR) and a level of Minimum Required Net Revenues (MRNR) associated with the separate repayment studies for each Case. Although the accounting and financing treatments are different between the two Cases, there is concern that the choice of a longer expense deferral period increases the difference in the revenue requirements amounts between the two Cases. The 6-year "restated" average annual comparable conservation cost in the Program Case revenue requirement is $155.1 million. The 6-year average annual conservation cost amount in the 7(b)(2) Case is $136.0 million with the choice of Alternative 3, deferral over 5 years (Study, WP-10-E-BPA-06, Appendix B, Summary Analysis – Accounting /Financing Treatment of Expensed Conservation Costs, B-10). The average annual Program Case costs $19.1 million more than the 7(b)(2) Case (Program Case costs are 14 percent greater than 7(b)(2) Case costs). This comparability analysis favors the choice of a shorter deferral period.

5) *7(b)(2) Rate Analysis:* The rate impact analysis results demonstrate that without a decision to defer the first-year conservation costs, there is a spike in rates in the first year. In addition, the rate analysis results demonstrate that a deferral policy of 4 to 7 years would provide rate savings of $1.55/MWh to $2.13/MWh compared to an accounting treatment of expensing the conservation expenditures in the year they were incurred. The rate analysis showed that a 15-year deferral period would provide rate savings of $2.52/MWh compared to the expense treatment. The incremental rate savings of $0.98/MW to $0.39/MWh associated with the 15-year alternative over Alternatives 2 through 5 are outweighed by the increased financing costs, longer cost recovery time, and the lack of cost comparability associated with this alternative and the Program Case.

In conclusion, the choice of a 5-year deferral and amortization period achieves the best balance between mitigating the rate impacts associated with a "supersized" conservation program and the negative consequences associated with deferring the first-year operating expenses.

Q. Why was a 5-year deferral period chosen over a 7-year deferral period?

A. The 5-year deferral period reduces the cost (interest expense) of undertaking conservation in the 7(b)(2) Case by $37.5 million compared to the 7-year deferral period. The 5-year deferral shortens the recovery period by approximately 1.5 years (weighted average recovery period) compared to the 7-year deferral period. The 5-year alternative provides greater cost comparability of conservation accounting/financing treatments between the two Cases when compared to the 7-year alternative.

Section 9: Reserve Benefits

Q. Do you propose to make any changes to the assumptions regarding reserve benefits used in the 7(b)(2) rate test?

A. Yes. In the Initial Proposal, we are assuming a small amount of DSI load (402 aMW), with firm power deliveries sold at the Industrial Firm Power (IP) rate. BPA is hopeful that it will be able to negotiate contract amendments that will allow it to sell firm power to DSI loads for FY 2010-2011. Although prior DSI contracts have provided the Federal Columbia River Power System (FCRPS) with reserves through BPA's ability to restrict or interrupt portions of DSI loads, the actual contract provisions to restrict or interrupt the load are uncertain at this time. The Initial Proposal assumes a value on this interruptibility of $0.01/MWh, based on the current contract provisions in effect during FY 2009. WPRDS, WP-10-E-BPA-05, section 2.2.1. The assumed aluminum load of 385 aMW for the rate period, *id*., results in an increase in the revenue requirement for the 7(b)(2) Case of approximately $20,000/year. Documentation, WP-10-E-BPA-06A, Table 2.5.3. This treatment of reserve benefits is different from prior rate proposals, where reserve resources for the 7(b)(2) rate test were modeled by assuming the addition of natural gas-fired single cycle combustion turbines as a first phase of resource acquisition before resources were acquired from the 7(b)(2) resource stack. Forecast DSI loads are small compared to past rate cases, BPA’s right to restrict or interrupt this load is uncertain, and the value of reserve benefits included in the Program Case is insignificant to the 7(b)(2) rate test. Thus, it is not necessary to model the treatment of reserve benefits for the Initial Proposal in the manner performed in earlier rate cases.

Section 10: Rate Analysis Model

Section 10.1: RAM2010 Model Description

Q. What type of computer model is required to conduct the 7(b)(2) rate test?

A. To calculate the annual PF rates for the Program and 7(b)(2) Cases for an appropriate rate comparison, a model that replicates BPA's ratemaking processes should be used. The Program Case modeling must produce a projection of annual rates that reflect BPA's ratemaking methodologies and the data available for the rate period, extended to the four subsequent years, while the 7(b)(2) Case modeling must allow the incorporation of the 7(b)(2) assumptions.

Q. What computer models has BPA previously used to conduct the 7(b)(2) rate test?

A. In BPA's WP-85 rate case, when BPA first conducted the 7(b)(2) rate test, BPA used the FORTRAN-based Supply Pricing Model. BPA continued to use the Supply Pricing Model in subsequent wholesale power rate cases through the WP-96 rate case. In the WP-02 rate case, BPA discontinued use of the Supply Pricing Model and turned to the 2002 Rate Analysis Model (RAM2002), which consisted of five large Excel spreadsheets that worked together by the use of Visual Basic macros. In the WP-07 rate case, BPA used the 2007 Rate Analysis Model (RAM2007), a single automated Excel spreadsheet, to conduct the test. The WP-07 Supplemental rate case 7(b)(2) rate test was performed using the 2009 Rate Analysis Model (RAM2009), which was based on RAM2007. We are now using RAM2010, an updated version of RAM2007.

Q. Please briefly describe RAM2010.

A. RAM2010 is a large Excel spreadsheet model that is automated with Visual Basic macros. RAM2010 is operated through a pop-up menu and explicitly shows the rate results after each major ratemaking step. RAM2010 automatically determines which of the potential participating REP utilities would be eligible to exchange as the unbifurcated PF and PF Exchange rates are developed. RAM2010 calculates the PF Slice product cost for each year and incorporates those data into the calculation of the rate period non-Slice PF Preference rate.

Q. *Does the RAM2010 model used to conduct the Initial Proposal 7(b)(2) rate test meet the criteria cited above?*

A. Yes. RAM2010 is the model used to implement BPA's ratemaking processes; therefore, it precisely replicates the rate period rates. The forecasts and policy assumptions used in the Program Case of the 7(b)(2) rate test are also used in the calculation of proposed rates for the Initial Proposal. The forecasts and assumptions are easily extended to the four subsequent years, and the 7(b)(2) Case modeling allows the incorporation of the 7(b)(2) assumptions. RAM2010 conducts the 7(b)(2) rate test as one of several ratemaking steps to produce annual rates.

Q. *How does RAM2010 incorporate those portions of the Implementation Methodology that determine how the 7(b)(2) Case rate projections are made?*

A. The 7(b)(2) Case sections of RAM2010 differ from the Program Case sections of RAM2010 by the five section 7(b)(2) assumptions:

1) *The within or adjacent DSI loads are added to the PF sales forecast, and no IP load or rate class is assumed.* For the rate period, a small amount of service to the DSIs is forecast in the Program Case; therefore, there is a small addition in the RAM2010 to the 7(b)(2) Case PF load due to this DSI service.

2) *7(b)(2) Customers are served with FBS resources not obligated to other non-preference loads under contracts existing as of the effective date of the Northwest Power Act.* For the rate test period, the FBS available to serve PF load is modeled in such a way that it is the same size in the 7(b)(2) Case as in the Program Case due to this provision. Because we have not fully completed some needed display changes, the displayed size of the FBS appears slightly larger in the 7(b)(2) Case when compared to the Program Case. This disparity in the display does not

change the resulting rate projections in either the Program Case or the 7(b)(2) Case.

3) *No section 5(c) REP takes place, and no PF Exchange load or rate class is assumed.* For the rate test period, REP costs and loads are not included in the 7(b)(2) Case.

4) *A section 7(b)(2)(D) resource stack with resources sorted from least- to most-costly is constructed to serve 7(b)(2) Customers after the FBS is exhausted. In addition, PF sales forecasts are increased by the annual conservation resources that are included in the 7(b)(2)(D) resource stack.* For the rate test period, 7(b)(2) Customer load in the 7(b)(2) Case is increased by conservation resources, and the model goes to the 7(b)(2)(D) resource stack to serve 7(b)(2) Customer load in the rate test period. The amount of conservation is limited to a level that BPA has actually acquired in the past, giving effect to obsolescence considerations and the projected amounts of conservation to be acquired during the rate test period.

5) *Reserves are included as an increased cost to the 7(b)(2) Customers. The cost of 7(b)(2) Customer resources reflects that financing benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case.* For the rate test period, we increase the revenue requirement in the 7(b)(2) Case by $20,000/year for a very small amount of reserve benefits to match the level of reserve benefits that DSI loads provide in the Program Case. Differences in increased resource costs due to the removal of financing benefits are incorporated in the 7(b)(2)(D) resource stack.

Q. How is RAM2010 organized?

A. RAM2010 has three main steps: a Cost of Service Analysis (COSA) step, a Rate Design step, and a Slice Separation step.

Q. Please provide a brief description of the RAM2010 COSA step and Rate Design step.

A. The RAM2010 COSA step follows BPA's rate directives by determining the costs and credits associated with the three resource pools (FBS resources, Exchange resources, and new resources) available to serve loads and then allocating the resource costs to two rate pools, 7(b) (PF loads), and 7(c) (IP loads) plus 7(f) (NR and firm FPS loads). In addition, costs and credits not associated with the resource pools are allocated pursuant to section 7(g). After this initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in sections 7(b) and 7(c) of the Act. RAM2010 performs these rate adjustments, including the 7(b)(2) rate test, in its Rate Design step. The Rate Design step of RAM2010 concludes with the final calculation of the Rate Design step rates – the PF Exchange rate and the NR rate. *See* Brodie et al., WP-10-E-BPA-16, section 4, for a fuller discussion of RAM2010.

Section 10.2: Modeling Changes

Q. What changes were made to RAM2007 in developing RAM2010?

A. There are five principal changes to RAM2007:

(1) The composition of the 7(b)(2)(D) resource stack was changed as discussed in sections 6, 7, and 8 above.

(2) The costs of the resources in the 7(b)(2)(D) resource stack are now based in real FY 2010 dollars.

(3) The "starting" resource cost values for FY 2010 for non-conservation resources in the 7(b)(2)(D) resource stack were adjusted so that the average cost of the resource for the entire 6-year rate test period (FY 2010-2015) in the 7(b)(2) Case is equivalent to the average cost for the resource in the Program Case.

(4) Changes were made to the treatment of BPA's service to Port Townsend Paper, where service was changed from an FPS sale to an IP sale; and service to

aluminum DSIs was changed from a monetized power sale to an assumed sale of physical power at the IP rate.

(5) Changes were made to the calculation of the individual 7(b)(3) Supplemental Rate Charges applied to the individual PF Exchange rates.

Q. Why are the costs of resources in the resource stack now based on real FY 2010 dollars?

A. The cost of resources contained in prior rate test models was based on real FY 1980 dollars. The change to FY 2010 dollars reduces the range of error due to rounding when using the GDP inflator/deflator index factors when escalating costs from the starting year dollar values contained in the resource stack to the purchasing power dollar costs of a later rate test period year. Removing 30 years of price changes reflected in the GDP inflator/deflator values from 1980 dollars to 2010 dollars reduces the level of rounding errors when changes in price levels are made in the model.

Q. Why are the “starting” resource cost values for FY 2010 for non-conservation resources in the resource stack adjusted so that the average cost of the resource for the entire 6-year rate test period (FY 2010-2015) in the 7(b)(2) Case is equivalent to the average cost for the resource in the Program Case?

A. This adjustment addresses changes in the annual costs of resources that are not addressed by annual price level changes alone. The rate model uses a single starting cost amount that is changed only for annual price level changes by application of the GDP inflator /deflator values. The adjustment made to the starting FY 2010 resource values is described and documented in the cost calculations for each of the non-conservation resources in the Study, WP-10-E-BPA-06, Appendix C. This change is necessary to more accurately model the non-conservation resource costs in the resource stack and to ensure that the average cost of Type 1 non-conservation resources over the rate test period is equivalent between the Program Case and the 7(b)(2) Case.

Q. How did you change the treatment of BPA service to Port Townsend Paper?

A. For ratemaking purposes, service to Port Townsend Paper had been included as an FPS contract that did not exist at the time of enactment of the Northwest Power Act. As such, the sale was included in the load obligations of the Program Case, but the sale was not included in the loads to be served in the 7(b)(2) Case. In the Initial Proposal, we assume that service to Port Townsend Paper is a power sale under the IP rate schedule. In the Program Case, this change in status from FPS sale to IP sale does not affect the load resource balance. However, in the 7(b)(2) Case, the 7(b)(2) Customer loads are increased by the 17 aMW IP sale to Port Townsend Paper. Previously, as a post-Northwest Power Act FPS sale, the Port Townsend Paper sale was not included in the 7(b)(2) Case loads but, because it is now redefined as an IP sale, the load is included as 7(b)(2) Customer load.

Q. How did you change the treatment of BPA service to aluminum DSIs?

A. For ratemaking purposes, service to aluminum DSIs had been included as a monetized power sale in the WP-07 Supplemental Final Proposal. In the prior rate case, the expected costs of the monetized power sale, $59 million per year, were included in the revenue requirement in both the Program Case and the 7(b)(2) Case. In the Initial Proposal, we assume that service to the aluminum DSIs is a physical sale under the IP rate schedule. In the Program Case, this change in status from a monetized power sale to an actual IP sale affects the load resource balance, which creates the need for more system augmentation. In the 7(b)(2) Case, the 7(b)(2) Customer loads are increased by the 385 aMW assumed IP sale to aluminum DSIs. The increased system augmentation increases the FBS by 396 aMW in both the Program Case and the 7(b)(2) Case.

Q. *What is the rate effect of this change in status for BPA's service to Port Townsend Paper?*

A. The increased 7(b)(2) Customer load in the 7(b)(2) Case causes the RAM2010 to take one more resource in the first year from the 7(b)(2) resource stack, which remains on for each subsequent year. This added cost increases the 7(b)(2) Case rates, reduces the 7(b)(2) rate test trigger, decreases the PF Exchange rate, and slightly increases the net REP benefits. The change for the aluminum DSIs does not change the draw from the resource stack, because the increased 7(b)(2) Customer load is accompanied by an increase in the size of the FBS.

Q. *Does the change that was made to the calculation of the individual 7(b)(3) Supplemental Rate Charges affect the 7(b)(2) rate test?*

A: No. This change occurs after the rate test and affects how the cost of the 7(b)(2) rate protection is recovered, but does not change the amount of the rate protection.

Q. *In developing RAM2010, have other changes been made to the RAM2007 used in the WP-07 Supplemental Proposal?*

A. Yes. Some minor modeling changes have been made to produce the most current version of RAM2010. These changes were made to either correct slight errors in the calculations or to make the calculations more transparent. These changes are relatively minor.

Section 10.3: Pending Modeling Changes

Q. *Are there any corrections to the RAM2010 that need to be made since the Initial Proposal rates were calculated?*

A. Yes. There are two small discrepancies in the rate modeling in the RAM2010. First, the marginal cost shape of the energy and the demand charges for the rates are unchanged in RAM2010 from the WP-07 Supplemental rate proceeding, whereas a different marginal cost shape is shown in chapter 2 of the WPRDS, WP-10-E-BPA-05. RAM2010 will be updated to incorporate the shape shown in the WPRDS. Second, the flat load shape assumed for the IP and NR loads is not updated for the actual monthly HLH and LLH hours in the FY 2010 to FY 2015 time period.

Q. Do you believe these problems would make a material difference in the calculation of the 7(b)(2) rate test trigger shown in section 12 below?

A. No. The allocation of costs to the various rate pools is done on an annual aMW basis and is not affected by the assumed marginal cost shaping of the monthly energy charges or by the actual monthly HLH and LLH hours. It is only after the revenue requirement for each rate class is determined that the monthly energy and demand charges are shaped to recover that revenue requirement. Because the 7(b)(2) rate test is conducted using annual average rates, the shape of the monthly energy and demand charges does not affect the calculation. However, this discrepancy will be corrected for the Final Proposal.

Section 11: Average System Costs And Forecast Residential Exchange Loads

Q. Does your testimony address the ASC inputs and forecast residential exchange load used as inputs in RAM2010?

A. No. Testimony concerning ASCs and forecast residential exchange load inputs into RAM2010 is found in Russell et al., WP-10-E-BPA-18.

Section 12: Summary of 7(b)(2) Rate Test

Q. What are the results of the Initial Proposal 7(b)(2) rate test?

A. The 7(b)(2) rate test triggers by 8.07 mills/kWh, and 7(b)(2) Customers are eligible for rate protection of approximately $1,029 million total for FY 2010-2011. *See* WPRDS Documentation, section 2, Table 2.5.9.

Q. Does this conclude your testimony?

A. Yes.