B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2010 Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

IMPLEMENTATION OF 7(b)(2)
(FY 2010-2011)

April 2009

WP-10-E-BPA-39

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REBUTTAL TESTIMONY of

WILLIAM J. DOUBLEDAY, RAYMOND D. BLIVEN,

PAUL A. BRODIE, and MICHAEL J. MACE

Witnesses for Bonneville Power Administration

SUBJECT: IMPLEMENTATION OF 7(b)(2) (FY 2010-2011)

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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, and my qualifications are contained in WP-10-Q-BPA-14.

A. My name is Raymond D. Bliven, and my qualifications are contained in WP-10-Q-BPA-06.

A. My name is Paul A. Brodie, and my qualifications are contained in WP-10-Q-BPA-09.

A. My name is Michael J. Mace, and my qualifications are contained in WP-10-Q-BPA-39.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. Mr. Doubleday, Mr. Bliven, Mr. Brodie, and Mr. Mace submitted direct testimony on the implementation of section 7(b)(2) of the Northwest Power Act in Doubleday *et al*., WP-10-E-BPA-15. Mr. Doubleday, Mr. Bliven, and Mr. Brodie submitted direct testimony on BPA's Cost of Service Analysis and rate design adjustments in Brodie *et al*., WP-10-E-BPA-16. Mr. Bliven also submitted direct testimony, with other witnesses, regarding power rates policy in Bliven and Lefler, WP-10-E-BPA-10; regarding an overview of wind integration in Mainzer *et al*., WP-10-E-BPA-22; and regarding rate design in Fisher *et al*., WP-10-E-BPA-30.

Q. Please state the purpose of your rebuttal testimony.

A. The purpose of this rebuttal testimony is to respond to the parties' direct testimonies regarding BPA's implementation of the section 7(b)(2) rate test.

Q. How is your testimony organized?

A. This testimony consists of 7 sections. Section 1 explains the purpose and scope of the testimony. Section 2 discusses issues related to the treatment of conservation in the 7(b)(2) Case, and is presented in five subsections. Subsection 2.1 discusses the conservation load adjustment made in the 7(b)(2) Case. Subsection 2.2 discusses conservation savings amounts and costs in the 7(b)(2) resource stack. Subsection 2.3 discusses conservation accounting and financing treatments in the 7(b)(2) Case. Subsection 2.4 discusses the criteria and analyses used to evaluate alternative deferral periods for expensed conservation costs. Subsection 2.5 discusses conservation financing benefits under section 7(b)(2)(E)(i) of the Northwest Power Act. Section 3 discusses Power Resources Cooperative's 10 percent share of the Boardman Coal Plant resource in the context of the resource stack. Section 4 explains load differences and adjustments. Section 5 discusses the treatment of value of reserves in the 7(b)(2) Case. Section 6 discusses uncontrollable events. Section 7 discusses proposed rate model changes and results.

Section 2: Treatment of Conservation in the 7(b)(2) Case

Section 2.1: Conservation Load Adjustment

Q. PPC et al. (JP8) argue that BPA should assume that conservation resources were acquired in their historical manner and make adjustments for their costs only as required by section 7(b)(2)(E). O'Meara et al., WP-10-E-JP8-01, at 3. JP8 claims that under this method, section 7(b)(2)(D) is fully satisfied to the extent that BPA conservation programs are purchased from preference customers pursuant to section 6. Id. JP8 states that it does not understand the Northwest Power Act to require an explicit load adjustment for BPA's historical conservation programs or for conservation programs to be placed in a "resource stack." Id. Please respond.

A. We believe this is largely an issue that was previously addressed in BPA's WP-07 Supplemental Rate Proceeding. Nevertheless, our understanding is that since the very first 7(b)(2) rate test was performed in FY 1984 (establishing rates for July 1, 1985-September 30, 1987), BPA has consistently followed a formal Legal Interpretation of Section 7(b)(2) of the Northwest Power Act (Legal Interpretation). The Legal Interpretation assumes that conservation is a resource available to the resource stack in the 7(b)(2) Case.

The Legal Interpretation recognizes that section 3(19)(B) of the Northwest Power Act specifically defines conservation as a resource. Furthermore, conservation is acquired pursuant to section 6 of the Act. Section 6(a)(1) states that "[t]he Administrator shall acquire such resources through conservation…." The term "such resources" refers to resources sufficient to meet the Administrator's contractual obligations under section 5 of the Act to provide electric power to meet firm power loads. Therefore, the Legal Interpretation has consistently recognized that conservation is a Type 1 resource that must be included in the 7(b)(2) Case resource stack. *See* Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06, Attachment 1, at 10.

BPA's Implementation Methodology of Section 7(b)(2) (Implementation Methodology) addresses the 7(b)(2) load forecast in Section V, Subpart 1:

> The initial loads that will be used in the 7(b)(2) Case will be the same General Requirements as those used in the Program Case, except that they will not include estimates of programmatic conservation savings being acquired by BPA because conservation is a non-FBS resource. In addition, conservation is a resource acquired by the Administrator pursuant to section 6 and, therefore, conservation resources are required to be included in the 7(b)(2) Case resource stack. Because conservation resources must be included in the resource stack to be drawn to meet remaining loads if needed, they have not already been acquired, and therefore they cannot have reduced the loads of the 7(b)(2) Case. To remove the effects of the acquisition of conservation, the 7(b)(2) Customer loads will be increased by conservation being acquired by BPA.

As with BPA's Legal Interpretation, BPA has consistently implemented the foregoing provisions of the Implementation Methodology. BPA's inclusion of conservation resources in the 7(b)(2) Case resource stack and the treatment of increasing the 7(b)(2) Customer loads has been followed consistently since the first 7(b)(2) rate test was performed in 1984. It is only since BPA's WP-07 Supplemental Rate Proceeding that any parties to BPA's rate cases objected to this approach. BPA presented a thorough discussion of its approach and legal analysis of the conservation load adjustment issue in the 2007 Supplemental Wholesale Power Rate Case Administrator's Final Record of Decision (WP-07 Supplemental ROD) (Conformed), WP-07-A-05, Chapter 16.3, at 429-471. The record of that proceeding has been adopted as part of the record of this proceeding and is hereby incorporated as part of this response.

In summary, we properly adjusted the loads in the 7(b)(2) Case for conservation, consistent with the updated and revised 2009 Section 7(b)(2) Implementation Methodology (2009 Implementation Methodology). The 2009 Implementation Methodology instructs to adjust the loads in the 7(b)(2) Case for conservation resources that are available for selection in the resource stack. BPA's WP-07 Supplemental ROD (Conformed), WP-07-A-05, Chapter 16.3, at 429-471, previously explained that increasing loads in the 7(b)(2) Case for conservation is consistent with both the language of the Northwest Power Act and the intent underlying the 7(b)(2) rate test.

Section 2.2: Savings and Cost of Conservation in the Resource Stack

Q. APAC claims BPA has committed a "clerical-type error" in the data used for conservation programs in the years 2008 through 2015. Wolverton, WP-10-E-AP-01, at 3-4. APAC claims the problem appears to be that the costs are left identical in the gross and net cases. Id. Please respond.

A. The aMW savings adjustments on page D-20 in the Section 7(b)(2) Rate Test Study (Study), WP-10-E-BPA-06, are made to the conservation savings associated with Conservation Rate Credits (CRC) and Market Transformation efforts. The aMW savings adjustments are reflected in the resource stack savings aMW amounts. The costs of acquiring the "net amount" of conservation savings are the same as the costs associated with the "gross savings amount." Our explanation for not reducing the costs of acquiring conservation savings from these two programs is stated in "Notes – Adjustments made to BPA's Conservation Program Expenditure Amounts to Arrive at Section 7(b)(2) Amounts." *See* Study, WP-10-E-BPA-06, at D-22, Notes 3 and 4. The notes state:

> 3. No reduction in expenditures for the CRC program was made. The rates charged all BPA customers for FYs 2008-2015 included CRC costs. It would be inequitable and not feasible to conduct a CRC program where only load following customers were eligible to participate. In order to achieve the conservation savings that occur in the service of full-requirements customers, BPA also needs to undertake the CRC program for BPA's other customers who pay for CRC costs. In order for BPA and its customers to meet their portion of the NWPPC's regional conservation targets, the total expenditures for the CRC program would need to be incurred.
>
> 4. BPA's market transformation efforts are being achieved through the Northwest Energy Efficiency Alliance (NEEA) during the 2010-2015 period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA is projected to pay for approximately one-half of NEEA's operating budgets during this time frame. The expenditures that BPA pays NEEA have only a partial impact on reducing the Administrator's load obligations. The market transformation savings were reduced by sixty-four percent for the years 2008-2015, see Note 3 to the table, "net BPA Projected Conservation Program Savings -2008-2015 – Section 7(b)(2) Amounts." The amount of market transformation expenditures was not reduced. The reason for this is the fact that the amount that BPA is projected to pay NEEA is so material in amount, that it is critical in sustaining market transformation efforts in the region. In order to achieve the 33% of savings that were included in the "net savings" total, BPA would have needed to fund the program at the same level of effort that was associated with the "gross savings" level.

Thus, no "clerical-type error" was made.

Q. *In a RAM run it conducted, APAC reduced the conservation program costs by the annual ratio of the net-to-gross conservation savings. Wolverton, WP-10-E-AP-01, at 4. Do you agree with this adjustment?*

A. No. As explained in the response to the previous question, we correctly determined the cost of the "net savings" conservation amounts contained in the resource stack. No adjustment should be made to the costs of conservation savings contained in the resource stack.

Q. *APAC adjusted the assumed level of conservation to reflect both the effect of BPA's new Tiered Rates Methodology and the rate burden imposed on preference customers by the treatment of conservation. Wolverton, WP-10-E-AP-01, at 8. APAC assumed that post-2011, the level of conservation programs paid for by BPA would be reduced by 50 percent, partly because of the incentives caused by the higher Tier 2 rates and partly because of the severe financial penalty arising from BPA programs through the operation of the 7(b)(2) rate test. Id. APAC stated that it is reasonable to reduce the size of BPA conservation programs by 50 percent, assuming that the utilities will perform that amount at the local level in order to meet load-growth and conservation-planning requirements. Id. Please respond.*

A. We relied on the Section 7(b)(2) Implementation Methodology (Study, WP-10-E-BPA-06, Attachment 2) in developing conservation projections for the FY 2012-2015 time period. The rate test period, or the "Five-Year Period" used in the section 7(b)(2) rate test, consists of the rate recovery period (FY 2010-2011 in the WP-10 Power rate case) plus the ensuing four years (FY 2012-2015). Section IV of the Implementation Methodology, entitled "The Program Case," states:

> In performing the 7(b)(2) rate test, the Program Case is the Five-Year Period projection of the average annual power rates for serving the General Requirements of the 7(b)(2) Customers

> conforming with all the provisions of the Northwest Power Act before considering the effects of section 7(b)(2). All rate proposal determinations, decisions, and assumptions for the rate recovery period regarding revenue requirements, loads, resources, cost allocation, and rate design will be used. *All data for the ensuing four years will be consistent with or extrapolated from rate recovery period data. Ratemaking methodologies, such as those based on the rate directives in the Northwest Power Act and those used to allocate costs and revenue adjustments to BPA customer classes, will be unchanged over the Five-Year Period.*

(Emphasis added.) In November 2008, we updated conservation program estimates for the rate period (FY 2010-2011) based on the Integrated Program Review-1 (IPR-1) process results and extrapolated the conservation program projections (both conservation savings amounts and expenditures) to the ensuing four-year period of FY 2012-2015 in a manner that was consistent with the rate recovery period data. It is inappropriate and inconsistent with the Implementation Methodology to speculate on how conservation programs would change in the post-FY 2011 time period when BPA's new Tiered Rate Methodology would go into effect, because the ensuing four-year period is to be extrapolated in a manner that is consistent with the rate recovery period.

BPA has been modeling the 7(b)(2) rate test in a consistent manner since FY 1985. This modeling has included the 7(b)(2) load forecast adjustment of increasing 7(b)(2) Case loads for conservation savings that would not have incurred in the 7(b)(2) Case. It also has included placing both past conservation investments and projected conservation investments during the Five-Year Period into a resource stack to be drawn upon in a least-cost order to serve 7(b)(2) Customer loads. It has been only since the WP-07 Supplemental rate proceeding that APAC has described BPA's conservation programs as containing a "financing penalty." Any such alleged "penalty," however, has not been shown to have had any effect. Over the 24 years BPA has been implementing section 7(b)(2) of the Northwest Power Act, BPA has seen no evidence of any unwillingness on the part of BPA's customers to participate in its conservation programs due to any "financing penalty." Because BPA developed the current rate period conservation program levels with the participation of BPA's customers in both the IPR-1 and IPR-2 processes, and because there was no serious objection raised about a "financing penalty" within that process, we assume that the conservation program levels, both savings and expenditures, were reasonably determined. As noted, they were subject to thorough review by BPA and other interested parties in a public process. We assume that the conservation savings targets for the rate period were reasonable and achievable.

As noted above, the ensuing four-year period is to be extrapolated in a manner that is consistent with the rate recovery period. Again, it is inappropriate and inconsistent with the Implementation Methodology to speculate on the impacts, if any, of APAC's alleged "financing penalty" on the level of conservation savings that could be achieved in the post-FY 2011 time period. APAC's speculation and proposed 50-percent reduction of conservation savings for the post-FY 2011 period of the rate test period are unfounded.

Q. APAC and JP8 argue that BPA should remove conservation program savings (i.e., market transformation savings) that are not or were not purchased from preference customers. Wolverton, WP-10-E-AP-01, at 6-7; O'Meara et al., WP-10-E-JP8-01, at 4. APAC and JP8 claim that so-called market transformation programs, in particular, are not "purchased from" preference customers. Id. Rather, the parties state, they are acquired from the region through BPA's support of such organizations as the Northwest Energy Efficiency Alliance (NEEA), which is not a preference customer. Id. Please respond.

A. Although we are not lawyers, in order to respond to this argument we must note our laymen's understanding of the Northwest Power Act, which underlies our testimony. The actions BPA takes to acquire conservation are described in the Northwest Power Act. For example, section 6(a)(1) directs the Administrator to acquire conservation resources that are consistent with the Northwest Power and Conservation Council's Plan. Section 6(a)(1)(B) of the Northwest Power Act states that BPA is to provide "technical and financial assistance to, and other cooperation with, the Administrator's customers and governmental authorities to encourage maximum cost-effective voluntary conservation…." Section 6(b)(5) states that "the Administrator shall not reduce his efforts to achieve conservation and to acquire renewable resources installed by a residential or small commercial consumer to reduce load, pursuant to subsection (a)(1) of this section." Section 6(e)(1) states that to effectuate the priority given to conservation measures, the Administrator shall make use of his authorities to acquire conservation measures, implement conservation measures, and provide credits and technical and financial assistance for the development and implementation of conservation measures. Section 6(e)(2) recognizes that to the extent conservation measures or the acquisition of resources require direct arrangements with consumers, the Administrator shall make maximum practicable use of customers and local entities capable of administering and carrying out such arrangements.

Based on our understanding, BPA is properly providing market transformation support to NEEA to assist BPA's efforts to provide the most cost-effective means of developing and implementing conservation savings. NEEA is a regionally supported entity that provides direct assistance to BPA's utility customers and their retail consumers, including BPA's preference customers. Through BPA's financial support of NEEA, BPA achieves energy savings associated with energy-efficient appliances and compact fluorescent light (CFL) bulbs from 7(b)(2) Customers' residential and small commercial consumers. Indeed, NEEA's efforts achieve conservation savings across the entire Pacific Northwest region. NEEA's region-wide programs provide an economy of scale and related cost-effectiveness that can be achieved only through BPA's large financial commitment to NEEA on behalf of all of BPA's customers. These benefits result in a reduction in electricity demand on the local utility, which in turn delivers energy savings (otherwise known as conservation) to BPA. Thus, conservation acquired through market transformation allows BPA to purchase conservation savings from its customers pursuant to section 6 of the Northwest Power Act.

Conservation savings acquired through NEEA's market transformation efforts are some of "the least expensive conservation resources" within public bodies or cooperatives' service territories. As noted above, BPA's NEAA conservation expenditures allow the acquisition of demonstrated savings through reduced 7(b)(2) Customers' loads, achieved by encouraging retail consumers (consumers of energy-efficient products) to invest in energy-efficient appliances and CFLs. The value to BPA and its utility customers is that the acquisition or purchase of more-expensive generating resources is delayed. The commitment to conservation resources and the achievement of those savings in 7(b)(2) Customers' service territories through the directives of the Northwest Power Act would not have occurred in the hypothetical world of section 7(b)(2), where the commitment required by the Act would not have occurred. In substance, there is no difference in BPA's practice of funding NEEA's efforts to acquire conservation savings from 7(b)(2) Customer service territories compared to BPA providing monies directly to consumer-owned utilities to promote and foster their own conservation programs.

The 7(b)(2) rate test compares Program Case costs with 7(b)(2) Case costs. In the 7(b)(2) Case, only certain types of resources are used to serve public body, cooperative, and Federal agency loads: stated simply, resources that are available for use because they are not contractually committed to regional firm load, and resources that BPA purchased from such customers. This means that additional resources needed to meet load in the 7(b)(2) Case, in general terms, would be incremental to those of the public body, cooperative, and Federal agency customers themselves. If BPA pays money directly to such customers to acquire conservation savings from them, BPA acquires the conservation resource from them. If BPA pays NEEA to establish programs to obtain conservation savings from the same customers, BPA still acquires the conservation resource from such customers. The fact that BPA employs an agent to acquire conservation from public body, cooperative and Federal agency customers does not mean that BPA has not purchased the conservation from such customers.

Q. APAC argues that conservation savings attributable to rate discounts should be removed from the 7(b)(2) resource stack, as they do not constitute purchases from preference customers. Wolverton, WP-10-E-AP-01, at 6-7. Please respond.

A. For many of the same reasons noted above concerning market transformation conservation savings, we disagree with APAC's proposal to exclude conservation savings obtained through BPA's CRC Program (FY 2007-2015) from the 7(b)(2) resource stack. (Savings attributable to BPA's Conservation Rate Discount Program FY 2001-2006 were removed from the resource stack amounts as explained in the Study, WP-10-E-BPA-06, at D-18, Note 4.) We also disagree with APAC's premise that use of the rate credit mechanism does not constitute a purchase by BPA from respective consumer-owned utilities.

The CRC is described in BPA's 2010 Wholesale Power Rate Schedules and 2010 General Rate Schedule Provisions (GRSPs), WP-10-E-BPA-07, at 71-74, and is supported by the testimony of Ingram *et al*., WP-10-E-BPA-17. The CRC is unlike generic sales discounts used in business, which are generally a stated percentage discount of the gross sales on a transaction that is based on the quantity of purchases or payment within a prescribed time period. As described in the GRSPs, the monthly CRC amount is determined by each customer's average monthly forecast load over the 24-month rate period multiplied by 0.5 mills/kWh. Thus, the credit is based on the relationship of the amount of energy that is forecast to be purchased, which is related to the conservation savings potential in each customer's load service area. Providing the CRC to BPA's utility customers creates an incentive to the utility, and an obligation of the utility, to develop and acquire qualified conservation saving programs that are outlined in the CRC Implementation Manual. *See* http://www.bpa.gov/Energy/N/pdf/CRC-CAA_Imp-Manual_04-01-2009_FINAL.pdf. Customers can elect not to take part in the CRC program and thereby not receive CRC monies through their power bills. There are no penalties for customers that do not participate in the CRC. Customers that do participate must submit reports on their CRC expenditures into the Planning, Tracking, and Reporting (PTR) system. If the total CRC-qualifying expenditures are less than the total accumulated monthly credits, the customer is required to reimburse BPA for the difference.

BPA, with input from its customers, adopted the payment method of placing a credit on the utilities' bills because it was more efficient and less costly than issuing a separate check or other form of payment to the utilities, and it helped utilities to budget their conservation expenditures in their service territories. From an accounting standpoint, the receipt of the credit on a power bill is the same as if a check had been issued. From the utility's standpoint, it records a reimbursement for conservation expenditures already undertaken (credit a receivable), or it credits a liability for expenditures that it is obligated to incur. The power purchase expense (debit) should be recorded at the gross amount. For the year, BPA's CRC payments offset a utility's annual conservation expense or offset the amount that would be capitalized and recovered through annual amortization charges. From BPA's perspective, the payment of the CRC is recorded as an annual operating expense associated with BPA's conservation program. The CRC payments are included in the annual operating expenses contained in BPA's revenue requirements, which are recovered through BPA's power rates. *See* Study, WP-10-E-BPA-06, at B-10, line 14 (the composition of line 18-annual conservation expense).

From the perspective of BPA's utility customers, treating the CRC as a credit that reduces the cost of power purchased by the utility would not be a proper accounting treatment, because it would not be supported by Generally Accepted Accounting Principles. As noted above, the CRC monies establish an obligation on the part of the utility to undertake conservation expenditures, which are an operating expense of the period or an investment in an intangible asset (conservation savings). Thus, it would be inappropriate to subtract the CRC monies from purchased power expenses. APAC's argument that the form of BPA's payment as a credit on monthly power bills does not constitute an amount of compensation or "purchase from such customers by the Administrator pursuant to section 6" is simply incorrect.

Section 2.3: Conservation Accounting and Financing Treatments

Q. JP8 recounts that BPA has proposed to defer, amortize, and finance the historically expensed portion of the 255 aMW of conservation resources selected from the 7(b)(2) resource stack in FY 2010 over a 5-year period. O'Meara et al., WP-10-E-JP8-01, at 5. JP8 states that BPA's accounting and financing treatment of conservation resources in the 7(b)(2) Case is not appropriate. Id. at 5. JP8 states that, given that the useful life of a generating resource is 15 years, the costs should be spread over the 15-year life of the resource. Id. JP8 argues that for costs of an asset with a useful life of 15 years, any expenditures on conservation resources out of the 7(b)(2) resource stack should be evenly spread over the 15-year life. Id. Please respond.

A. PPC previously raised this argument in BPA's WP-07 Supplemental rate proceeding. The issue was addressed by BPA at length in the WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 429-471. The WP-07 Supplemental rate proceeding record, which includes all litigants' arguments, has been incorporated into the record of this proceeding and is hereby incorporated as part of this response.

Q. *The IOUs do not agree with the proposal to finance and amortize expensed conservation over 5 years in the 7(b)(2) Case. LaBolle et al., WP-10-E-JP1-01, at 25. The IOUs argue that expensed conservation should be recovered in the year it is incurred. Id. The IOUs state that in any event, expensed conservation should not be assumed to be financed and amortized over a period as long as five years as in the Initial Proposal. Id. The IOUs state that it is standard practice in the industry to recover such expenses in the year they are incurred—"just like the Program Case treatment." Id. The IOUs state that prior to the WP-07 Supplemental ROD, BPA recovered expensed conservation in the year it was incurred not only in the Program Case but also in the 7(b)(2) Case. Id. The IOUs state that BPA continues to properly follow the practice of recovering Expensed Conservation in the Program Case in the year that it is incurred; there is no basis for using a different number of years for recovery of Expensed Conservation in the 7(b)(2) Case. Id. Do you agree?*

A. We do not agree with the IOUs' position on expensed conservation costs in the 7(b)(2) Case. As noted in the Study, WP-10-E-BPA-06, Appendix B, the proposed treatment of deferring conservation expenses and amortizing and financing these costs over a 5-year period as allowed under Statement of Financial Accounting Standards No. 71 (SFAS NO. 71), is the most appropriate accounting treatment for these costs in the 7(b)(2) Case. We analyzed and considered several alternatives, but the 5-year deferral alternative struck the best balance between the large increase in first year costs that caused a rate spike and the desire to minimize the additional financing costs by recovering these costs over a short period of time. We agree that these expenditures are operating costs of the year incurred, and such expenses generally would be expensed as they are in the Program Case. However, the nine vintage years of conservation costs selected from the resource stack and the amount of expensed costs ($325.1 million) that would be recovered in the first year of the rate test period warrant the deferral treatment in the 7(b)(2) Case. *See*

Study, WP-10-E-BPA-06, at B-6 and B-7. In the Program Case, there is only one vintage year of conservation being acquired per year, and therefore the Program Case does not face the rate shock problem that occurs in the 7(b)(2) Case. Without the deferral treatment, the 7(b)(2) Case rates would experience a first year rate shock that would result in a 7 percent increase in first-year rates when compared to the 5-year deferral alternative. It is reasonable to believe that the JOA in the 7(b)(2) Case would have elected the short-term deferral treatment to avoid this large increase in first-year rates.

Q. The IOUs state that a change in the period over which expensed conservation is financed and amortized in the Program Case is not one of the five assumptions to be made for the 7(b)(2) Case under the Northwest Power Act. LaBolle et al., WP-10-E-JP1-01, at 29. Do you agree?

A. No. Section 7(b)(2)(E) explicitly states that the 7(b)(2) Case is to assume "the quantifiable monetary savings … resulting from reduced public body and cooperative financing costs as applied to the total amount of resources … identified under subparagraph [7(b)(2)](D) of this paragraph, … are not achieved." Both the Legal Interpretation and the Implementation Methodology are clear that this means BPA financing is not applied to resources in the 7(b)(2) Case resource stack. As noted below in Section 2.4, the establishment of the 7(b)(2) Case resource stack and the accounting and financing policies that govern the resources in the stack stem from one of the five assumptions (section 7(b)(2)(D) of the Northwest Power Act). As pointed out in the response in Section 2.4, one would expect the average annual conservation costs to be different between the two cases, because the creation of the resource stack and the selection of resources from the stack in least-cost order would result in a different population of conservation costs being recovered in the two cases. In addition, as pointed out in the next response, the number of years of prior-period conservation costs being recovered in the Program Case is greater in this period of time due to the mixture of costs from three different accounting amortization treatments and time periods that are being recovered in the 7(b)(2) Case. Given those facts, one would generally expect the Program Case conservation costs to be different and higher than the 7(b)(2) Case costs. The $19 million annual average higher cost amount of the Program Case is a product of both the larger amount of amortization costs associated with 21 vintage years of conservation programs in the Program Case (FY 2010) compared to the 9 years of conservation costs in the 7(b)(2) Case (FY 2010), as well as the difference in the treatment of expensed conservation costs in the two cases.

During FY 1985-2001, BPA's accounting treatment regarding the useful life over which capitalized conservation investments should be amortized was 20 years, using the straight-line method for financial statement reporting purposes. This accounting policy was used in both the Program Case and the 7(b)(2) Case. In FY 2002, the decision was made to adopt the declining years amortization treatment for ConAug Conservation investments over the Subscription Contract period for financial reporting purposes. In BPA's WP-02 and WP-07 rate cases, 1) the Program Case continued to amortize the historical capitalized costs pertaining to FY 1985-2001 over 20 years, 2) ConAug Conservation investments made during FY 2002-2006 were amortized using the declining years method outlined above, and 3) starting in FY 2007, BPA adopted a third amortization treatment for conservation investments of 5 years using the straight-line method. The change in accounting amortization period for conservation investments occurring in FY 2007 was primarily due to the need to replenish U.S. Treasury borrowing authority. During the entire FY 1985-2015 time period, the 7(b)(2) Case used an accounting amortization useful life determination that matched the composite useful life of conservation investments contained in the Council's Plan (preferred list of conservation investments), which was 20 years for FY 1985-2001 and 15 years for time periods after FY 2001, as determined in the WP-07 Supplemental rate proceeding.

Rate cases since FY 2001, including the present rate case, continue to use different accounting and financing periods associated with conservation investments between the two cases. It was a correct determination that the JOA in the 7(b)(2) Case would have followed an accounting treatment for capitalized conservation costs that was based on an objective independent determination of useful life, and the Council's useful life determination fits this requirement. It was also a correct determination in the Program Case (which follows BPA's accounting and financial policies used for financial statement reporting purposes) that the amortization/financing policy of amortizing and financing capitalized conservation over 5 years was appropriate to be responsive to BPA's need to sustain access to U.S. Treasury borrowing authority.

In the 7(b)(2) Case, access to U.S. Treasury borrowing authority is not a limitation, and this concern should not drive the borrowing and amortization policies for that Case. Similarly, one would not choose to have the financing and accounting policies used for financial statement reporting purposes determined by the hypothetical world of section 7(b)(2). It would be inappropriate for the accounting and financing policies of one case to dictate the accounting policies and treatments that must be followed by the other case. Thus, BPA's policy since FY 2001 has been to allow the conservation accounting and financing policies governing the Program Case and the 7(b)(2) Case to be different.

In the WP-07 Supplemental ROD (Conformed), WP-07-A-05, Chapter 16.4, at 477, BPA stated "The Act states nothing directly and implies very little concerning the nature of BPA's accounting and financing policies for conservation expenditures, although it does require that the Administrator implement the Act in a sound and businesslike manner. 16 U.S.C. § 839f(b)." The ROD (Conformed) also stated at 498-499 that:

> From a ratemaking perspective, the JOA and its member COUs would adopt a balanced approach in dealing with the upward rate

> pressures associated with the high first-year costs of conducting a large (approximately 255 aMW in the WP-10 Case) conservation program and concerns over accumulating substantial balances of deferred regulatory assets that would be have to be recovered from future rate periods. A balanced and prudent approach would be to capitalize and finance the smaller portion of direct acquisition costs (approximately 34 percent of total conservation costs in WP-10 Case) of the conservation program over their useful life (15 years), while spreading the large amount of first-year expensed costs (66 percent of total conservation costs in WP-10 Case) over a one-year to useful-life period based on the conservation resources selected from the resource stack and their relationship to the total package of resources selected to meet 7(b)(2) Customer loads in the prospective rate case.

In the present rate case, the treatment from the perspective of the JOA in the 7(b)(2) Case continues this balanced approach in selecting the deferral and financing period for the expensed conservation costs. This balanced approach mitigates the rate spike associated with the cumulative expensed costs associated with nine vintage conservation resources at a reasonable level of additional interest expense and a reasonably short recovery period. The short recovery period mitigates the potential for accumulating successive increments of deferred costs that could create upward rate pressure for future rate periods. As noted above, the accounting and financing policies that govern the 7(b)(2) resource stack are independent of the accounting and financing policies that govern conservation resources in the Program Case. The establishment of the 7(b)(2) resource stack stems from section 7(b)(2)(D), and in order to implement this assumption it is necessary to develop accounting policies and procedures governing resources in the stack that are responsive to the operating circumstances of the JOA in the prospective rate case.

The 7(b)(2) Case accounting treatment of deferring expensed costs and financing them over the deferral period is also consistent with the provisions of the Implementation Methodology: "For conservation resources acquired by BPA, the financing benefits may include an increased amount of debt financing compared to the Program Case. The amount of debt financing assumed in the 7(b)(2) case will be determined in the relevant rate case." *See* Study, WP-10-E-BPA-06, Attachment 2, at 9.

In conclusion, the different accounting treatment for expensed conservation costs in the 7(b)(2) Case is not explicitly described in the five assumptions of section 7(b)(2). However, it is necessary to adopt the change in accounting policy to be responsive to the JOA's operating circumstances in the 7(b)(2) Case. Just as it was reasonable for BPA to adopt a 5-year amortization and financing period for capitalized conservation for financial reporting purposes for use in the Program Case in 2007, it is also reasonable to adopt the deferral treatment for expensed conservation costs in the 7(b)(2) Case. It is not reasonable to assume that the JOA would have elected an accounting policy that would have placed the cumulative amount of expensed costs associated with nine conservation resources into the FY 2010-2011 7(b)(2) rate period. It is necessary to adopt this change in the accounting treatment for expensed costs in order to implement the resource stack and the selection of nine conservation resources in the first year of the rate period. This position is consistent with BPA's past practices of establishing different amortization periods for capitalized conservation costs in the two cases, which has been followed since FY 2002.

Section 2.4: Deferral Periods for Expensed Conservation Costs

Q. JP8 criticizes the second of BPA's proposed criteria for evaluating the appropriate accounting and financing treatment of conservation resources in the 7(b)(2) Case, "Additional Financing Costs Associated with Deferring First Year Expensed Costs," also referred to as "Financing Cost Impacts." O'Meara et al., WP-10-E-JP8-01, at 6. JP8 states that in comparing different options, BPA calculates interest expenses from deferring the historically expensed costs and then compares those to the historical expense. Id. JP8 states that this comparison overstates the impact of financing because *it does not appear to take into account the time value of money. Id. JP8 argues that BPA should apply a net present value calculation to the interest expenses to make the comparison valid. Id. Please respond.*

A. JP8 is correct that there are differences in the time value of money that are not taken into account in comparing the differences in financing cash flows. BPA performs the analysis in the following manner:

- The vintage conservation resources in the resource stack were used to analyze all alternatives, and all resources were stated in FY 2010 dollars.
- All resources were selected from the resource stack in the same order and in the same amounts contained in the Initial Proposal.
- Conservation resources costs were adjusted for inflation projections using the inflator/deflator values contained at page B-5 of Appendix B to the Study as corrected by WP-10-E-BPA-06-E01.
- The interest rate used to finance the capitalized conservation expenditures over 15 years is 4.57 percent across all alternatives. The short-term interest rates used for financing the deferred expensed conservation costs is based on the interpolation direction on page 16 of the Financing Study. *See* Study, WP-10-E-BPA-06, Appendix A.
- The annual debt service payment amount is calculated with increasing principal/decreasing interest expense over the term of the debt, similar to mortgage-based financing. Once the annual debt service payment is calculated, it remains fixed over the financing period.

This analysis will be revised by restating the cash flows in constant 2010 year dollars by using the Inflator/Deflator indices that are outlined in the errata corrections designated WP-10-E-BPA-06-E01 to page B-5 of the Study, WP-10-E-BPA-06. It is not appropriate to speculate on the cost of capital or the appropriate discount rate the JOA would use, which would have been used to perform a net present value analysis of the six different alternatives. The JOA would also take into account the additional cost associated with the deferral of the principal in terms of additional borrowings that would be incurred, or additional capital that would be raised, to be able to undertake additional utility investments of the JOA and its member utilities stemming from the deferral of the return of principal. This cost associated with the delay in replenishing reserves/working capital is not quantified in the analysis. Staff desires to keep the analysis simple and omit unnecessary complexity.

The adjustment for the time value of money would change the magnitude of the dollar differences between the different alternatives, but it would not change the outcome of the analysis, which is the conclusion that "[t]he amount of additional interest expense and cumulative rate impacts of deferring these costs into later rate periods support the choice of a shorter deferral period." Doubleday *et al.*, WP-10-E-BPA-15, at 22. For the Final Proposal, we propose to adjust the analysis for the time value of money.

Q. JP8 addresses BPA's third criterion, "Number of Years Required to Recover Conservation Costs," also referred to as "Cost Recovery." O'Meara et al., WP-10-E-JP8-01, at 6. JP8 states that under this criterion, BPA weighs the various financing options by the total percentage of conservation costs that each option recovers during the rate test period. Id. JP8 argues that this is not relevant to BPA's stated goal of determining how a JOA would handle the costs of conservation resources, due to the fact that the "Rate Test Period" is an interpretation of the language of section 7(b)(2), which is completely exogenous to the hypothetical world in which the JOA is deemed to be making its decisions. Id. Stated differently, JP8 claims BPA assumes incorrectly through this criterion that the construct of the "Rate Test Period" would have any significance on the hypothetical JOA's operating decisions. Id. Please respond.

A. BPA stated its position on the accounting for, and financing of, conservation expenditures at great length in the WP-07 Supplemental ROD (Conformed), WP-07-A-05, Chapter 16.4, at 471-509. Our position on the accounting for, and financing of, conservation costs is different than JP8's position. Our position is that the same accounting policies that govern the determination of which conservation expenditures are capitalized and expensed that are present in the Program Case carry over to the 7(b)(2) Case. BPA has consistently followed the same expense and capitalization determination policies concerning conservation costs for over 27 years.

In the WP-07 Supplemental ROD (Conformed), WP-07-A-05, Chapter 16.4, at 471-509, BPA noted: 1) the large number of vintage conservation programs that were being selected from the resource stack in the first year of the rate test period; 2) that a substantial portion (66.24 percent of the Initial Proposal's selected Conservation Costs) of the conservation resource expenditures are expensed costs; and 3) that the JOA in the 7(b)(2) Case would have mitigated the first year "rate spike" that would occur if these expensed costs were placed in rates. BPA concluded that the most logical accounting and financing treatment for these expensed costs would be to defer these costs under SFAS No. 71 and to finance their cost over an appropriate period. Based on an updated review of these factors, we concluded that the conservation costs should be financed over a period of 5 years in the WP-10 Initial Proposal.

Given the fact that the JOA would have chosen to defer these expensed costs and to finance them over a period of years, our objective was to develop criteria that would be useful to the JOA decisionmakers in determining the period of years to finance and recover these expensed costs. We propose the rate test period of 6 years because it is a convenient time period associated with the current rate case. Following prudent business practices, we propose that the JOA would choose a short time period of 3 to 7 years over which to perform the analysis, because of the fact that 66.24 percent of the costs were expensed costs that would normally be recovered in the year incurred.

We agree that the rate test period of 6 years would have been exogenous to the JOA's frame of reference. Although the recovery amounts would be different, the conclusions drawn from the analysis using a slightly different short-term time period would be the same. The decisionmaker would want to establish what percentage of the total conservation costs is recovered using the different deferral periods by a "time-certain," and it could use 3 years to 7 years in performing the analysis. The percentage of total conservation costs recovered is only one of two cost recovery metrics that we consider under the Cost Recovery Consideration Criteria. We also present a weighted average recovery period analysis in the Study, WP-10-E-BPA-06, Appendix B, at B-9. This second metric is not constrained by the "time-certain" limitation of the first metric. We consider both metrics in analyzing the deferral period and in proposing to defer and finance the expensed conservation costs over 5 years. It is reasonable to conclude that the JOA would weigh the benefits of reductions in 7(b)(2) Customer rates quantified by Criterion 5 against the disbenefits of incurring additional interest expense (Criterion 2) and the increased recovery time (Criterion 3) associated with longer deferral periods. A longer discussion of our analysis of the five decision criteria can be found in our response to the IOUs' direct case.

Q. *JP8 also addresses the fourth criterion, "Cost Treatment Comparability Between the Program Case and the 7(b)(2) Case," also referred to as "Comparability of Costs." O'Meara et al., WP-10-E-JP8-01, at 7. JP8 does not see a concern given that the difference in revenue requirements between the two cases is a result of attempting to implement the five assumptions directed by section 7(b)(2). Id. JP8 argues that choosing to minimize or mitigate the difference in revenue requirements as criteria appears to be in direct conflict with the purpose of the statute. Id. JP8 also claims that any concerns*

BPA may have about differences created between the Program Case and 7(b)(2) Case revenue requirements are, again, exogenous to the hypothetical world in which the JOA is operating and should be excluded on that basis as well. Id. Please respond.

A. We have a valid concern over the comparability of cost and financing treatments between the two cases. In an "ideal world" associated with performing the 7(b)(2) rate test, both the Program Case and the 7(b)(2) Case would have identical amortization periods associated with capitalized costs. BPA's Program Case amortization time period of 5 years was chosen primarily due to the need to "replenish" borrowing authority to sustain the financing of capitalized conservation expenditures. In the 7(b)(2) Case, BPA has consistently used the composite useful life of conservation resources developed by Council staff to finance and amortize conservation resources, which is currently over 15 years. Thus, capitalized costs that comprise 33.76 percent of the total conservation costs selected from the resource stack during the rate test period are amortized and financed over 5 years in the Program Case, and over 15 years in the 7(b)(2) Case. Both amortization and financing periods are appropriate for the respective cases.

We do not seek to diminish the differences between the amortization periods for expensed conservation costs in the two cases. Prior to the WP-07 Supplemental rate proceeding, BPA's practice of recovering in rates expensed conservation costs in the year incurred was followed in both the Program Case and the 7(b)(2) Case. The decision to defer and finance the large amount of "first year" expensed conservation costs in the 7(b)(2) Case is the correct accounting treatment for the 7(b)(2) Case in order to mitigate the first year "spike" in rates. The treatment of expensing these costs as incurred in the Program Case is also the correct accounting policy in the Program Case and is also followed by many 7(b)(2) Customers.

Although it is true that the creation of the resource stack and the corresponding accounting and financing policies associated with those resources is the result of one of the five assumptions, we are concerned that the difference in accounting and financing policies concerning the deferral and financing of conservation first-year expensed costs could have an impact on the rate test. It is due to our concern over the issue of comparability of conservation costs that one of the five criteria addresses cost comparability. Although we are not attempting to eliminate the differences attributable to the accounting and financing policies between the two cases, we cannot ignore the fact that the choice of setting the deferral period for expensed conservation costs can have an impact on the rate test. BPA developed the comparability criterion so that we as well as all other rate case parties could gauge whether the deferral and financing period for expensed costs in the 7(b)(2) Case is reasonable given the importance that this decision can have on the 7(b)(2) rate test results. Based upon the comments received from other rate case parties in their direct cases regarding the comparability of conservation costs, it is apparent that the criterion is serving a useful purpose.

We agree that this criterion is exogenous to the world that the JOA decisionmaker(s) would be concerned about. The other four criteria address the frame of reference of the JOA decisionmaker. As we note in responding to the IOUs' direct case, the principal reason the JOA and its member utilities would not choose Alternative 6 (Deferring and Financing the Expensed Costs over Fifteen Years) is due to the fact that the additional amount of interest expense and the long recovery period for costs that are normally expensed in the year incurred would not be a prudent or sound business decision. The cost treatment comparability criterion serves as a useful frame of reference or benchmark to test the overall reasonableness of the cost of conservation in the 7(b)(2) Case. The cost treatment comparability criterion reinforces the decisions made from the perspective of the JOA not to choose Alternatives 1 and 6 in favor of Alternatives 2-5. Alternatives 1 and 6, in addition to being inferior choices from the perspective of the JOA, would also decrease the comparability of conservation costs between the two cases to a significant degree. With regard to Alternative 6 on this point, "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 between the two Cases." Doubleday *et al.*, WP-10-E-BPA-15, at 23.

We propose to continue to consider all five criteria in analyzing and deciding the appropriate number of years that expensed conservation resources should be deferred and financed in treating these expenses as deferred charges under SFAS No. 71.

Q. The IOUs argue that BPA should not be concerned that expensing expensed conservation in one year in the 7(b)(2) Case causes a price "spike" in the first year that might distort costs in the 7(b)(2) Case. LaBolle et al., WP-10-E-JP1-01, at 25-26. The IOUs argue that focusing on the first-year effect of recovering expensed conservation in FY 2010 is misplaced, because BPA conducts the section 7(b)(2) rate test over a six-year period. Id. The IOUs argue that it is inappropriate to depart in the 7(b)(2) Case from the treatment of expensed conservation in the Program Case—recovery in the year incurred. Id. Do you agree?

A. No. The JOA in the 7(b)(2) Case is still setting rates for the same 2-year period (FY 2010-2011) as the Program Case. Alternative 1 - Expense in the Year Incurred still produces a 2-year rate of $27.99/MWh compared to the 2-year rate of $26.17 under Alternative 3 - the 5-year Deferral. *See* Study, WP-10-E-BPA-06, at B-11. The 7(b)(2) rate test is exogenous to the JOA's operating circumstances and reality. As noted in Doubleday *et al*., WP-10-E-BPA-15, at 20, "The purpose of the analysis (comparison of the alternatives) 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) Customer utilities."

Q. The IOUs state that using a 5-year financing and amortizing period for expensed conservation in the 7(b)(2) Case, rather than recovering it in the year incurred as in the Program Case, results in conservation debt service in the 7(b)(2) Case that is about $19 million lower over the six-year period than conservation debt service in the Program Case. LaBolle et al., WP-10-E-JP1-01, at 26. The IOUs claim that this difference in debt service inappropriately and unnecessarily biases the result of the section 7(b)(2) rate test, causing the trigger to be $19 million higher than it would be if this error were corrected. Id. The IOUs state that, in contrast, recovering expensed conservation in the 7(b)(2) Case in the year that it is incurred results in conservation debt service that is nearly identical in the Program Case and the 7(b)(2) Case. Id. Do you agree?

A. We do not agree with the IOUs' characterization of the Cost Comparability Criterion - Factor 4 in the Study, WP-10-E-BPA-06, at B-10. We do agree with the quoted difference of $19 million in average annual conservation costs between the Program Case and 7(b)(2) Case, and that the amounts cited by the IOUs are correct. However, we do not agree with the IOUs' conclusion that Alternative 1 (Expensed Costs are Expensed in the Year Incurred) should be chosen because the 6-year average conservation costs are more alike, when compared to the Program Case, than Alternative 3's treatment of deferring and financing the expensed conservation costs over 5 years. The IOUs' conclusion that the $19 million average annual difference in conservation debt service between Alternative 1 and Alternative 3 for the 7(b)(2) Case results in the Trigger Amount being $19 million higher is incorrect. There is a much larger set of costs that make up the total revenue requirement for each year of the rate test period for each respective case. The trigger amount is the result of discounting the rates for each respective year of the rate test period back to FY 2010 and averaging the rates for each case and subtracting the average 7(b)(2) Case rate from the average Program Case rate.

Concerning the comparability of the average annual conservation cost amounts, we have consistently stated that the populations of conservation cost amounts between the Program Case and the 7(b)(2) Case are not comparable. The creation of the 7(b)(2) Case resource stack and the accounting and financing policies governing the resources in the resource stack is due to the operation of one of the five assumptions, namely section 7(b)(2)(D) of the Northwest Power Act. The amounts of the Federal base system resources, along with other resources used to serve the loads in each respective case, are different and not comparable. The creation of the resource stack and the selection of resources from the stack in least-cost order results in a different population of conservation costs being recovered in the 7(b)(2) Case. One should expect a difference in the annual conservation cost amounts between the two cases. The table on page B-10 of the Study, WP-10-E-BPA-06, presents a comparison of similar categories of costs between the Program Case and the 7(b)(2) Case. We did not state that the amount of conservation costs between the two cases should be equal. We included the table because it is useful to know the degree of difference in conservation costs, and because parties to the rate case would want to know the amount of the difference.

The $19 million average annual difference in conservation costs will change dramatically over time due to the different accounting treatments governing conservation resources in the two cases. The Program Case conservation cost for FY 2010 contains the amortization expense of 21 vintage years of historical conservation capitalized costs:

- Conservation Amortization – 20-year lives; (12) vintage years FY 1990-2001,
- ConAug Conservation Amortization – declining year method, (6) vintage years FY 2002-2007, and
- Conservation Amortization – 5-year lives; (3) vintage years FY 2008-2010.

Thus, the Program Case for FY 2010 contains the amortization of *21 years* of capitalized conservation investments totaling $50.3 million. *See* Study, WP-10-E-BPA-06, at B-10, lines 28-29. By FY 2021, all of the cost recovery associated with conservation that was amortized over 20 years will have occurred, and all of the cost recovery of ConAug Conservation will have been completed by the end of FY 2011. Only the amortization expense associated with *5 years* of capitalized conservation costs for FY 2016-2021 will be present in the FY 2021 Program Case conservation costs. The FY 2010 Program Case also contains interest expense of $13.8 million associated with FY 1998-2010 conservation bonds and third-party financed conservation bond debt service of $5.1 million. *See* Study, WP-10-E-BPA-06, at B-10, lines 30 and 31. In addition to these costs associated with prior years' conservation efforts, the FY 2010 Program Case contains the expensed costs associated with the FY 2010 conservation program totaling $86.9 million. *See* Study, WP-10-E-BPA-06, at B-10, line 25.

In comparison, the 7(b)(2) Case revenue requirement for FY 2010 contains the debt service associated with *9 years* of vintage conservation investments relating to the years FY 2001-2009, whose capitalized costs are financed over a 15-year period, and the expensed costs that are being deferred and financed over a 5-year period totaling $88.1 million. *See* Study, WP-10-E-BPA-06, at B-10, line 49. One can readily see that the population of costs between the cases is very different. In addition, the shape of the annual amounts of conservation costs is different between the two cases. The "Similar Program Case Comparison" on line 42 of page B-10 has a fairly even annual cost stream during the rate test period (FY 2010-2015) of $160.4 million to $149.2 million dollars. Alternative 3 for the 7(b)(2) Case (5-year deferral/financing of expensed conservation costs on line 49 of page B-10) presents a rapidly increasing annual stream of costs ranging from $88.1 million in FY 2010 to $185.0 million in FY 2014 before decreasing to $137.2 million in FY 2015. The cost stream associated with Alternative 1 "front-loads" the conservation costs. Alternative 1's expensing of costs in the year incurred (the position advocated by the IOUs) would have presented the following debt service amounts (capitalized and expensed costs in millions): FY 2010, $340.5; FY 2011, $104.4; FY 2012, $111.3; FY 2013, $118.6; FY 2014, $126.1; and FY 2015, $130.4.

In summary, the IOUs' argument that Alternative 3 biases the rate test result is based on a false premise. The IOUs assume that the level of conservation costs should be the same in the two cases, when in fact they should be different, because there are a different number of years of conservation costs present in the two cases, and the amount of conservation costs and savings for each year is different. The two cases are meant to be different due to the operation of sections 7(b)(2)(D) and 7(b)(2)(E) of the Northwest Power Act. In addition, for clarification purposes, the $19 million difference (which the IOUs assert gives rise to a bias in the rate test result) is not primarily due to the choice of Alternative 3 versus Alternative 1. As pointed out above, the difference arises because of 21 years of conservation cost recovery present in FY 2010 in the Program Case, while only 9 years of conservation cost recovery is taking place in the 7(b)(2) Case. Thus, we disagree with the IOUs' conclusion that the choice of the five-year deferral period (Alternative 3) biases the rate test result.

Q. *The IOUs describe how the 1-year and 5-year financing and amortizing alternatives compare using BPA's five criteria. LaBolle et al., WP-10-E-JP1-01, at 27-28. The IOUs state that under Criterion 1 (Resource Stack Composition), BPA states that 73 percent of the average megawatts of first year resources are conservation resources. Id. The IOUs argue, however, that the Initial Proposal fails to explain why this fact argues for any particular financing and amortizing method. Id. The IOUs state that under Criterion 2 (Financing Cost Impacts), financing and amortizing over 5 years as opposed to 1-year recovery increases the interest paid by $90 million. Id. The IOUs point out that under Criterion 3 (Cost Recovery), BPA states that 73.79 percent of the total costs are recovered in the rate test period under Alternative 1 (No Deferral) versus 57.43 percent for Alternative 3 (Financing Over 5 Years). Id. Thus, the IOUs claim Alternative 1 (No*

Deferral) is the best choice 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. Id. Please respond.

A. The IOUs have mischaracterized our analysis of the five criteria. A more detailed description of our analysis of the five criteria is presented below.

Criterion 1 – 7(b)(2) Selected Resource Composition (Study, WP-10-E-BPA-06, at B-6 and B-7). This criterion identified the number of resources, their quantity, and the composition of the resource costs:

> 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.

Doubleday *et al.*, WP-10-E-BPA-15, at 21-22.

Criterion 5 – 7(b)(2) Rate Analysis (Study, WP-10-E-BPA-06, at B-11). In support of the analysis of the five criteria, we testified:

> 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.

Doubleday *et al.*, WP-10-E-BPA-15, at 24. The first criterion established the amount of expensed conservation costs that would be expensed in the first year of the rate test period ($325.1 million) if the decision to defer these costs was not made, and the fifth criterion quantified the amount of the rate spike associated with the 7(b)(2) Case rates if Alternative 1 (expense in the year incurred) was chosen. In contrast to the IOUs' conclusion that Criteria 1 and 5 should be considered as neutral factors that should be given little or no weight, we determined that these two criteria taken together established the basis for the JOA to decide to defer and finance the expensed conservation costs and to reject the choice of Alternative 1. These two criteria establish that Alternative 1 should not be adopted given the large amount of "first year" expensed costs and the related spike in rates that would occur if Alternative 1 were selected.

Criterion 2 – Financing Costs (Study, WP-10-E-BPA-06, at B-8). This analysis quantifies the amount of additional interest expense that is associated with the alternative deferral periods. The analysis indicates there is a relatively tight band of financing costs associated with the alternatives to defer the expensed costs over 4 to 7 years of $72.9 million to $127.7 million in nominal dollars over the FY 2010-2021 period. The financing cost analysis indicates that the additional interest expense associated with the 4 to 7 year deferral periods amounts to only 9.42 percent to 16.5 percent of the original historical expensed costs. The cost of avoiding the rate spike and lowering rates during the FY 2010-2011 rate period by a range of $1.55/MWh to $2.13/MWh for Alternatives 2-5 (quantified by Criterion 5 on page B-11) for all 7(b)(2) Customer loads during this time period would be equal to the $72.9 to $127.7 million (nominal dollars) in additional interest expense spread over the FY 2010 to FY 2021 time period. Subsequent rate periods would continue to see a decrease in rates as a result of the FY 2010 deferral decision. The rate of decrease would diminish over subsequent years. There would be an additional cost associated with the deferral of the principal in terms of the additional borrowings that would be incurred to be able to undertake additional utility investments of the JOA and its member utilities stemming from the deferral of the return of principal. This cost associated with the delay in replenishing reserves/working capital is not quantified in the analysis.

The additional interest expense associated with deferring the expensed costs over a 15-year period associated with Alternative 6 amounts to $312.4 million (nominal dollars) in additional costs over the FY 2010-2029 time period. The rate analysis shows that a 15-year deferral period would provide rate savings of $2.52/MWh compared to the expense treatment (Alternative 1). The incremental rate savings of $0.98/MW to $0.39/MWh associated with the 15-year deferral period in Alternative 6 over the 4- to 7-year deferral treatments contained in Alternatives 2 through 5 are outweighed by the increased financing costs that raised the amount of historically expensed costs by an additional 40.34 percent. In addition, Alternative 6 substantially increases the length of time over which expensed costs would be recovered. The JOA and its member utilities would not choose a deferral period of 15 years to recover costs that are normally expensed in the year incurred. The JOA and its member consumer-owned utilities, in adopting a balanced approach of deferring the large cumulative amount of first-year expensed costs to mitigate the resulting rate shock, would choose to recover the expensed costs over a relatively short period of years based on the following considerations:

- The JOA and its members would want to operate in a manner that is consistent with sound business principles.
- They would be cognizant of matching the current costs of operations with current rates. Although the JOA and the member utilities would be able to capitalize and defer conservation expenditures, sound business practices and prudent utility practices would temper the amount of deferred regulatory assets.
- They would maintain high credit ratings, so the cost of financing their operations would be low and they would have good access to credit markets.
- They would maintain adequate financial reserves for operations and to meet or exceed debt coverage ratio requirements associated with bond covenants and operating lines of credit.

At the conclusion of this first phase of the analysis, we concluded that the JOA decisionmakers would eliminate Alternatives 1 and 6 from consideration for the reasons discussed above.

During the second phase of the analysis, the choice between deferring and financing the expensed costs over 4 to 7 years is based on the desire to capture a substantial amount of the rate benefits (decreased 7(b)(2) Customer rates) quantified by Criterion 5 while at the same time mitigating the additional interest expense (Criterion 2) and decreasing the recovery time (Criterion 3) associated with the expensed costs. As explained above in the discussion of Criterion 2 - Financing Costs Associated with the Different Deferral Periods (page B-8), there is a relatively tight range of additional interest expense associated with Alternatives 2-5. "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." Doubleday *et al.*, WP-10-E-BPA-15, at 22.

Criterion 3 – Cost Recovery (Study, WP-10-E-BPA-06, at B-9). Two separate metrics were developed to gauge the level of cost recovery. The first metric, which we discussed in testimony, quantifies the percentage of total historical conservation costs that are recovered by the end of the 6-year rate test period. Alternatives 2, 3, and 4, which defer the expensed cost over 4 to 6 years, all recover more than 50 percent of the total conservation costs used to serve 7(b)(2) Case loads during the rate test period. Alternative 5, which defers the expensed costs over 7 years, recovers 46.03 percent of the total conservation costs by the end of the rate test period. The second metric presented in the cost recovery analysis quantifies the weighted average recovery period associated with the capitalized costs being recovered over 15 years in all Alternatives, with the expensed costs being recovered over the range of 4 to 7 years under Alternatives 2 through 5. The weighted average recovery period ranges from 7.71 years for

Alternative 2 (Deferral of expensed costs over 4 years) to 9.70 years for Alternative 5 (Deferral of expensed costs over 7 years). "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 asset or redeployed to meet other operating needs of the utility." Doubleday *et al.*, WP-10-E-BPA-15, at 22-23.

Criterion 4 – Cost Comparability (Study, WP-10-E-BPA-06, at B-10.). This criterion serves as a useful frame of reference or benchmark to test the overall reasonableness of the cost of conservation in the 7(b)(2) Case. The analysis at page B-10 provides an understanding of the differences in the population of conservation costs that are present in the two cases and helps gauge the reasonableness of the decision concerning the number of years over which to defer and finance expensed conservation costs. As noted above, the principal reason the JOA and its member utilities would not choose Alternative 1 (Expense the expensed costs in the year incurred) is due to the significant spike in first-year rates that would result from that choice. In addition, the JOA and its member utilities would not choose Alternative 6 (Deferring and Financing the Expensed Costs over Fifteen Years) because the additional amount of interest expense and the long recovery period for costs that are normally expensed in the year incurred would not be a prudent or sound business decision. As stated in a previous response, Cost Comparability Criterion 4 would be exogenous to the reality of the JOA decisionmakers. However, this criterion reinforces the above decisions made from the perspective of the JOA not to choose Alternatives 1 and 6 in favor of Alternatives 2-5. Alternatives 1 and 6, in addition to being inferior choices from the perspective of the JOA, would also decrease the comparability of conservation costs between the two cases to a significant degree. With regard to Alternative 6 on this point, "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 between the two Cases." Doubleday, *et al.*, WP-10-E-BPA-15, at 23.

After analyzing the remaining Alternatives 2-5 against Criteria 2, 3, and 5, we determined that the 5-year amortization and financing period (Alternative 3) is the best choice.

Q. The IOUs state that if BPA does not adopt their recommendation to use Alternative 1, the analyses under BPA's decision criteria taken as a whole and BPA's treatment of expensed conservation in the Program Case support recovery of expensed conservation over a period of less than 5 years. LaBolle et al., WP-10-E-JP1-01, at 27-28. Do you agree?

A. We agree to a limited extent. As outlined in the previous answer, our proposal to choose a deferral and financing period of 5 years (Alternative 3) is objective, well reasoned, and supported by the analysis. However, Alternative 2 (Deferring and financing the expensed costs over 4 years) is very similar to Alternative 3. Its choice is also supported by the analysis. The primary difference between the two alternatives is the slightly higher degree of additional 7(b)(2) Customer rate savings achieved by Alternative 3, albeit at a slightly higher amount of interest expense and a slightly longer recovery period.

Q. The IOUs argue that expensed conservation should be recovered in the 7(b)(2) Case in the year in which it is incurred—just like the Program Case treatment. LaBolle et al., WP-10-E-JP1-01, at 29-30. The IOUs state that, in any event, financing and amortization of expensed conservation in the 7(b)(2) Case over a period as long as five years is unjustified, particularly under the five decision criteria identified in the Initial Proposal. Id. The IOUs argue that shortening the financing and amortization period in the 7(b)(2) Case for expensed conservation would increase consistency with the Initial Proposal's decision criteria. Id. Do you agree?

A. We do not agree that expensed conservation costs should be recovered in the 7(b)(2) Case in the year incurred, for the reasons stated previously. We do not agree that a deferral and financing period of 5 years is too long. The 5-year deferral and financing period is supported by the analysis using the five decision criteria present in the Initial Proposal. As noted previously, the results of the analysis using the 4-year deferral and financing period is very similar to the analysis results for the 5-year deferral and financing period. The analysis of the results for the 4-year period demonstrates that rate mitigation benefits were slightly less than the 5-year deferral period, but there is a benefit from decreased interest expense and a shorter recovery period associated with the 4-year deferral period alternative.

Section 2.5: Financing Benefits

Q. The IOUs state that, paradoxically, under the Initial Proposal, conservation debt service costs are lower in the 7(b)(2) Case than in the Program Case, even though BPA is required to assume that financing benefits were not achieved in the 7(b)(2) Case. LaBolle et al., WP-10-E-JP1-01, at 29. Please respond.

A. The financing rate used to finance capitalized conservation costs in the 7(b)(2) Case is the interest rate determined by BPA's independent financial advisor, Public Financial Management (PFM), of 4.57 percent. This rate is contained in Table A of the Study, WP-10-E-BPA-06, Appendix A at 5. This tax exempt rate is used to finance capitalized conservation costs over 15 years in the 7(b)(2) Case. This rate is the correct rate associated with higher financing costs that occur due to the absence of BPA's resource backing in the 7(b)(2) Case. If a BPA conservation purchase contract is used to acquire conservation for the Program Case using customer-issued tax exempt bonds, PFM projects a lower interest rate of 4.37 percent for Program Case conservation financed in that manner. As Note 3 to Table A states, "During the 2010 Power Rate Case study period FY 2010–2015, BPA projects that it will borrow $262 million for conservation investments using 5-year maturities with a weighted average (taxable) interest rate of 5.35%. The bonds will be issued through the U.S. Treasury so they are not comparable to the tax exempt rates included in the table." *Id*. We correctly use the 5-year tax exempt rate of 3.79 percent contained in Table A to finance the deferred conservation expenses over 5 years. We correctly incorporate the financing cost impacts associated with section 7(b)(2)(E)(i) of the Northwest Power Act in the calculation of conservation debt service costs in the 7(b)(2) Case.

Section 3: PRC's Boardman Coal Plant Resource

Q. The IOUs note that in the Initial Proposal, BPA includes the output from PRC's interest in the Boardman Coal Plant in the section 7(b)(2)(D) resource stack. LaBolle et al., WP-10-E-JP1-01, at 31. The IOUs state that the output from PRC's interest in the Boardman Coal Plant is not a Type 2 resource and is therefore not properly included in the section 7(b)(2)(D) resource stack. Id. The IOUs state that to be a Type 2 resource, the resource must necessarily be owned or purchased by a public body or a cooperative. Id. The IOUs argue the output from PRC's interest in the Boardman Coal Plant is not owned or purchased by a public body or a cooperative, and, therefore, it is not a Type 2 resource. Id. The IOUs argue the Initial Proposal incorrectly assumes that PRC is a public body or cooperative and incorrectly assumes that the resource is owned or purchased by PRC. Id. Please respond.

A. In responding to the IOUs' arguments it is helpful to establish the historical record concerning the PRC's 10 percent ownership interest of the Boardman Coal plant. Power Resources Cooperative was originally organized as Pacific Northwest Generating Company (PNGC). PNGC acquired the 10 percent ownership interest from Portland General Electric Company in or around 1980, when the Boardman Coal Plant went into operation. PNGC's operations concerning its ownership in the Boardman Coal plant were transferred to Power Resources Cooperative (PRC) in approximately 1995. The generation and transmission functions of the former PNGC were transferred/assumed by Pacific Northwest Generating Cooperative Power in approximately 1997. The ownership of PNGC, PRC, and the interests in the power generation of the Boardman Coal plant were represented by PNGC to BPA to have similar ownership interests prior to the time that Pacific Northwest Generating Cooperative Power was formed in 1997.

Exhibit A to this testimony includes Contract No. DE-MS79-86BP92300 between BPA and PNGC and its member utilities dated February 27, 1987. The contract provides for BPA to serve as agent for PNGC and its member utilities to schedule their share of the Boardman Project to short-term purchasers. Exhibit C to the contract establishes the utilities' share/interest of the Boardman project output. The contract states "Bonneville and each of the Utilities have separately entered into a Power Sales Contract as specified in Exhibit C which provides for the sale of power at Bonneville's Priority Firm Rate to meet each Utility's firm requirements for power." This provision and the underlying individual utility contracts provided the consumer-owned utilities with preference power to replace the Boardman project power that was owned by each utility and dedicated to each utility's load in its1981 Power Sales Contract's Firm Resource Exhibit (FRE). Note 1 to Exhibit C of the Contract made each individual utility's power sales contract part of Contract No. DE-MS79-86BP92300. Section 10 of the contract covered the contract's payment provisions. That section required each of the individual utilities to pay for all of the nonfirm displacement energy, surplus firm power, station service, and scheduling and management services for the Boardman project in relation to each utility's Project Share. The contract is signed by each of the 13 utility principals and the general manager of PNGC.

Exhibit B of this testimony includes two letters from BPA's Power Sales Office to PNGC dated August 11 and 30, 1989, concerning each consumer-owned utility's Firm Resource Exhibit. The letter of August 30, 1989, states "This is to notify you that the Bonneville Power Administration has approved each Pacific Northwest Generating Company member's request to remove the 5(b)(1)(B) contractual Boardman resource from their Firm Resource Exhibits (FRE) effective July 1, 1980 and for all subsequent years pursuant to section 12(b)(9) of the Power Sales Contract." Exhibits A and B establish that the membership of PNGC at that time and the ownership of the Boardman Project output were one and the same as outlined in Exhibit C of Contract No. DE-MS79-86BP92300. The payment provisions of the contract establish that each individual utility owner of the 10 percent share of the Boardman project was treated as an individual owner of its respective share of the project, and each individually assumed the responsibility for payment of its share of Boardman's operations as it related to Contract No. DE-MS79-86BP92300.

Exhibit C of this testimony is a June 17, 2008, email from Tyran Gardner, an administrative assistant at PNGC Power, to Jeremy Hyde of BPA, which established the list of PRC members at that time. The membership of PRC as of June 17, 2008, consisted of the same membership list contained in Exhibit C of Contract No. DE-MS79-86BP92300, with the exception that Lincoln Electric Cooperative, Inc's 2.74 percent interest in the 10 percent interest of PNGC succeeded by PRC's interest in the Boardman Project had been acquired by West Oregon Electric Cooperative, Inc. All of these owners of PRC's 10 percent interest in the Boardman Project are consumer-owned utilities that have current section 5(b) power sales contracts with BPA.

Our position, which is the same position of PNGC and its member utilities at the time Contract No. DE-MS79-86BP92300 was signed, is that PRC's interests in the Boardman Project have been purchased and/or assigned to PRC's membership as outlined in Exhibit C to Contract No. DE-MS79-86BP92300. PRC prepares annual operating budgets concerning the operation of the Boardman power plant that assign each of its members the economic interest and responsibility for Boardman's operations based on PGE's annual operating budgets for the plant, which can be found in the Study, WP-10-E-BPA-06, Exhibit C, at C-29 through C-34, plus the costs of PRC's operations. The operation of PRC is analogous to that of a partnership where each member receives the benefits and has the responsibility for its respective ownership share of the costs of operations related to the Boardman Coal Plant.

Q. *The IOUs argue that "PRC is not a public body or cooperative." LaBolle et al., WP-10-E-JP1-01, at 32-33. The IOUs claim that the original PNGC was not a public body (i.e., it was not a state, public power district, county, or municipality). Id. The IOUs state that BPA itself determined that the original PNGC was not a public body or a cooperative. Id. The IOUs state that because PNGC became PRC, PRC, like PNGC, is neither a public body nor a cooperative. Id. Thus, the IOUs claim, the output from PRC's interest in the Boardman project is not "owned or purchased by a public body or a cooperative." Id. Do you agree?*

A. We do not agree with the IOUs' argument. Our previous response establishes that the membership of PRC and the 13 consumer-owned utilities that own 100 percent of PRC's interest in the Boardman Coal Plant are one and the same.

Q. *The IOUs state that the Initial Proposal incorrectly assumes that the resource is owned or purchased by PRC. LaBolle et al., WP-10-E-JP1-01, at 33. The IOUs state that the resource is the <u>output</u> from PRC's interest in the Boardman Coal Plant, not the physical generating facilities. Id. The IOUs state that PRC has sold the output from its interest in the Boardman Coal Plant to Turlock Irrigation District. Id. The IOUs conclude, therefore, the output from PRC's interest in the Boardman Coal Plant is sold and is not available to serve general requirements in the 7(b)(2) Case. Id. Do you agree?*

A. BPA has previously stated its position concerning the IOU's argument that resources should not be included in the resource stack if the owner(s) of the economic interest to the resource sells the power output from the resource to another party outside the region. WP-07 Supplemental ROD (Conformed) , WP-07-A-05, Chapter 16.10, at 546-596. BPA presented a thorough discussion of its response and legal analysis to the IOUs' argument that the output of the preference customer's resource, once sold, could no longer be considered owned and available to the resource stack. The complete record of that proceeding has been adopted as part of the record of this proceeding and is hereby incorporated as part of this response. Further support for including the Boardman Coal Plant in the resource stack can be found in the Implementation Methodology. *See* Study, WP-10-E-BPA-06, Attachment 2, at 8: "These additional resources are defined in section 7(b)(2)(D)…. (b) existing 7(b)(2) Customer resources not currently committed to regional load by preference customers or IOUs…."

In conclusion: 1) PRC's 10 percent ownership in the Boardman Coal Plant is owned by 13 consumer-owned utilities that currently have and are projected to have section 5(b) power purchase contracts with BPA through the rate test period; 2) these 13 utilities, along with PRC, have sold their 10 percent portion of the Boardman Coal Plant outside of the region to the Turlock Irrigation District in California; 3) because of points 1 and 2, the Boardman Coal Plant resource is properly includable in the 7(b)(2) resource stack.

Q. The IOUs state that even assuming, <u>arguendo</u>, that output from PRC's interest in Boardman is included in the section 7(b)(2)(D) resource stack, BPA incorrectly includes the embedded cost of the Boardman project output. LaBolle et al., WP-10-E-JP1-01, at 34. The IOUs understand that PRC has sold the output from its share of the Boardman project to Turlock Irrigation District under a long-term contract. Id. Thus, the IOUs argue that if PRC's interest in the Boardman output is included in the section 7(b)(2)(D) *resource stack, it should be included at the long-term market price for power equivalent to that output. Id. The IOUs state that at a minimum, if PRC's interest in Boardman output is included in the section 7(b)(2)(D) resource stack, it should be included at the price that Turlock Irrigation District is paying PRC for such output. Id. Do you agree?*

A. No, we do not agree with the IOUs' position. BPA previously addressed this issue in the WP-07 Supplemental ROD (Conformed), WP-07-A-05, Chapter 16.10, at 577. The complete record of that proceeding has been adopted as part of the record of this proceeding and is hereby incorporated as part of this response. The consumer-owned utilities' ownership of PRC's 10 percent portion of the Boardman Coal Plant is correctly included at cost as reflected in PGE's operating budgets and other information available from PGE. We requested information from PRC on its additional costs associated with managing the 10 percent resource portion for its13 utility members, but PRC was not responsive to requests for this information.

Section 4: Load Differences and Adjustments

Q. APAC claims BPA made an error in the adjustment to loads because of an internal BPA communication error. Wolverton, WP-10-E-AP-01, at 4-5. APAC suggests there is a discrepancy between the amount of potential requirements load assumed to be reduced by conservation programs and the amount of "electrical" load needing to be augmented in the 7(b)(2) Case. Id. Please respond.

A. As we explained in Data Response NR-BPA-6, BPA Staff responsible for performing the load forecast assume that conservation savings from CRC and Market Transformation efforts are already embedded in the sum of utility forecasts that are used to establish the consumer-owned utility load forecasts for the rate case. Stated differently, the gross loads before "direct conservation savings" adjustments are already reduced for conservation savings attributable to CRC and Market Transformation efforts. "No forecast of energy savings is included in the load forecast. … As proposed, BPA will not forecast such savings in the load forecast, but will include any and all conservation savings that are achieved through the CRC toward meeting BPA's conservation target." Ingram *et al*., WP-10-E-BPA-17, at 6. We then subtract the conservation savings attributable to Conservation Direct Acquisition Bilateral Contracts with COUs and Federal agencies (17 aMW) and Third Party Contracts (5 aMW), which are not included in the utility-specific load forecasts, to arrive at PF load forecasts that are adjusted for conservation savings. It is important to consider that all of the information at issue concerns forecast projections. Forecast projections change over time, and inevitably the actual amounts will be different from the forecast projections.

Based on the later vintage of conservation savings projections (Study, WP-10-E-BPA-06, at D-23), the line item "Conservation Acquisition – Bilateral Contracts" contains an amount of projected savings for FY 2008, 8.0 aMW; FY 2009, 18.7 aMW; FY 2010, 6.2 aMW; and FY 2011, 19.6 aMW. The information on this line combines the savings totals for Utility & Federal Agency Bilateral Contracts and Third Party Contracts that are separate line items on Table 1 in the WPRDS Documentation, WP-10-E-BPA-05A, at C-6. The average annual amount for the 4 years is 15.6 aMW. Based on these later projections, the annual forecast loads for FY 2008-2011 are understated by 5.4 aMW per year (the difference between 21 aMW that was subtracted in preparing the forecasts and the 15.6 aMW). This same line item (page D-23) for the years FY 2012-2015 contains average annual savings projections for this category of 23.8 aMW. The forecasts for those years are overstated by 2.8 aMW (the difference between 21 aMW that is subtracted and the 23.8 aMW updated projection). We will update and revise the table on page D-23 for the Integrated Program Review (IPR)-2 results when they become final. In the Final Proposal, the revised amounts for this line item will be used to update both the load forecast amounts and the amounts in the resource stack for this category of conservation savings. Other categories of conservation savings will also be adjusted in the Final Proposal for the IPR-2 amounts, as previously noted in the Study, WP-10-E-BPA-06, at D-21, Note 1 and D-24, Note 1.

The 7(b)(2) Case loads are correctly stated based on the underlying Program Case load forecast projections discussed previously. Again, the Program Case forecasts contain an amount of conservation savings attributable to CRC and Market Transformation savings that are embedded (already incorporated) in the specific utility forecasts, which are reduced for the direct annual conservation savings associated with Utility & Federal Agency Bilateral Contracts and Third-Party Contracts. The Program Case loads are then increased by the amounts of conservation load savings that had not taken place, which are the reduced or "net amounts" of conservation savings that are documented in Appendix D to the 7(b)(2) Study to arrive at the 7(b)(2) Case loads. These reduced "net amounts" of conservation are the amounts of conservation that are reasonably projected to have the ability to reduce the Administrator's load obligation, as explained in the notes contained in Appendix D. In conclusion, APAC's proposed adjustments to the 7(b)(2) Case loads are unwarranted and would produce incorrect results in modeling the 7(b)(2) rate test.

Section 5: Value of Reserves in the 7(b)(2) Case

Q. The IOUs state that the value of reserves provided by the interruption rights on the DSI loads in the Program Case is, at a minimum, $17,083,440. LaBolle et al., WP-10-E-JP1-01, at 14. Therefore, BPA should assume that it will incur additional costs equal to, at a minimum, $17,083,440 in the 7(b)(2) Case. Id. Do you agree?

A. We agree with the portion of the IOUs' argument dealing with whether the 7(b)(2) Case revenue requirement should include the costs of reserves that are provided by the DSI contracts in the Program Case but not available in the 7(b)(2) Case. In the Initial

Proposal, the 7(b)(2) Case revenue requirement was increased by BPA Staff's estimate of the value of reserves provided by the assumed DSI contracts. Because no sales contracts to the DSIs existed at the time of the Initial Proposal, Staff made its best effort to estimate the value of reserves that a likely set of DSI contracts would provide. At this later date, Staff is recalculating its estimate of the value of reserves, and that more-current estimate will inform the additions to the 7(b)(2) Case revenue requirement. *See* Fisher *et al.*, WP-10-E-BPA-36.

Q. The IOUs state that if BPA were to decide to provide DSI benefits through monetary payments to DSIs (or through monetary payments or power sales through the local utility), that decision should not result in a reduction in the level of Residential Exchange Program (REP) benefits provided by BPA. LaBolle et al., WP-10-E-JP1-01, at 20-22. The IOUs state that if BPA were to decide to provide DSI benefits by a mechanism other than direct physical power deliveries by BPA under the IP rate, either the costs of the DSI service benefit monetary payments should be included in the 7(b)(2) Case costs or the power equivalent of the DSI benefits should be included as load in the general requirements of the PF Preference rate customers in the 7(b)(2) Case. Id. Do you agree?

A. In the Initial Proposal, we included the forecast DSI load in both the Program Case and the 7(b)(2) Case. However, we do not agree with the IOUs' proposed criteria that power service to the DSIs or monetary benefits to the DSIs have no effect on the REP benefits provided by BPA. The IOU criteria are not based on any of BPA's rate directives. We will include the proper amount of load and/or monetary benefit costs in both the Program Case and the 7(b)(2) Case, and the effect on the level of REP benefits will be an outcome of normal BPA ratemaking. No special criteria are called for, and none will be used. However, a test of the rate modeling showed the difference in rates and REP benefits when comparing comparable levels of power sales and monetary benefits *(i.e.*, when the net cost of DSI power sales equals the monetary benefit) is in the realm of "model noise". Based on this one test, the result the IOUs are concerned about may not be an issue.

Section 6: Uncontrollable Events

Q. The IOUs state that given the magnitude of BPA's activities and BPA's exposure to uncontrollable events, the absence of any costs of an uncontrollable event during this period demonstrates that BPA is applying unduly restrictive criteria when determining the costs of uncontrollable events for the purposes of conducting the section 7(b)(2) rate test. LaBolle et al., WP-10-E-JP1-01, at 36-37. Do you agree?

A. The IOUs previously raised this issue in BPA's WP-07 Supplemental rate proceeding. IOU Brief, WP-07-B-JP6-01, at 54. Pursuant to Hearing Officer Order WP-10-HOO-09, the administrative record of BPA's WP-07 Supplemental rate proceeding has been incorporated in the WP-10 record in order that litigants' arguments need not be repeated in direct or rebuttal testimony. BPA hereby incorporates the relevant elements of the WP-07 Supplemental rate proceeding record in response to the IOUs' argument. *See, e.g.*, WP-07 Supplemental ROD (Conformed), at 646-659.

Section 7: Proposed Rate Model Changes – Rate Model Results

Q. APAC proposes changes to RAM to update the rate determinations for the corrections previously presented by APAC in the WP-07 Supplemental rate proceeding. Wolverton, WP-10-E-AP-01, at 9-11. APAC acknowledges that its arguments and underlying testimony are detailed in the record for the WP-07 Supplemental rate proceeding and states that APAC will not re-argue here the positions taken in that case; APAC will simply apply its positions laid out there to the facts of this case. Id. Please respond.

A. BPA did not agree with APAC's proposed revisions to BPA's rate proposal in the WP-07 Supplemental rate proceeding, and we do not agree with those proposed revisions in the current WP-10 rate proceeding. Merely being able to produce scenario results does not validate the reasonableness of those results, particularly if the underlying assumptions are erroneous.

Q. APAC claims that the purpose of the statutory requirement to calculate rate test protection by incorporating one year plus the following four years is to remove an anomalous year or years from causing the rate test to trigger highly in favor of either preference customers or exchanging utilities. Wolverton, WP-10-E-AP-01, at 18. Do you agree?

A. In calculating the 7(b)(2) rate test over the rate period plus the ensuing four years, we produce an average rate test result that may be more stable over successive rate cases than if only one rate period is used in the calculations. We also believe that an "anomalous year" would most likely be the test year rather than any of the ensuing four years. The nature of forecasts is that the further out into the future they are made, the more the variables used in the forecast will tend to their long-term average. That is, using average water conditions and average annual cost and load growth trends for out-year forecasts is the norm, while a current exception from normal conditions will affect the near-term outlook. For example, if a forecaster is currently living though an economic downturn with dry water conditions when producing rate case forecasts, the next year's forecast may be affected by the current conditions, while forecasts for later years will be much less affected by current conditions than by established long-term trends. Also, if the same forecaster is currently observing average conditions, the forecaster is not likely to forecast anomalous conditions three or four years out. Therefore, because longer-range forecasts tend to be smoother than actual conditions or shorter-range forecasts, setting the 7(b)(2) rate test trigger on a longer set of forecast Program Case and 7(b)(2) Case rates (six years in the instant rate case) will tend to smooth the rate test results of successive rate cases and provide individual rate case results closer to the longer-term trend than if only the rate period Program Case and 7(b)(2) Case rate are used (two years in the instant rate case).

BPA uses an Average Present Value method to combine the annual stream of Program Case and 7(b)(2) Case rates to one rate per case before the rates are compared to calculate the rate test trigger. BPA's borrowing interest rate is used in the present value calculation. In this way the result is a present value from BPA's perspective; that is, by using BPA's borrowing rate, it can be assumed that just before the beginning of the FY 2010-2011 rate period, BPA would be indifferent between receiving the discounted revenue from the discounted FY 2014 rate or waiting until FY 2014 to receive the undiscounted FY 2014 revenues.

Q. APAC states that since the first rate test was run, BPA has taken the results of each of the five years in the rate test and discounted the difference between the Program Case and 7(b)(2) Case rates to a year prior to the test year using BPA's borrowing rate from the Treasury. Wolverton, WP-10-E-AP-01, at 18. APAC states that the traditional method used in RAM came into question when APAC noticed that out-year average system costs affected the rate test. Id. APAC claims that this result seemed to be contrary to the statutory requirement that the cost of the REP be excluded from the calculation of the rate test. Id. Please respond.

A. First, APAC's argument that out-year ASCs should not affect the rate test is directly contrary to section 7(b)(2). One of the five assumptions in section 7(b)(2) is that REP costs are excluded from the 7(b)(2) Case. REP costs are not excluded from the Program Case, however. Because the 7(b)(2) rate test trigger is derived from a comparison of the Program Case rates (with REP costs) and the 7(b)(2) Case (without REP costs), APAC is incorrect in stating that REP costs are excluded from the rate test. If REP costs are higher or lower in the rate period and the ensuing four years, it is expected that, all else equal, the Program Case rates will be different, and thus the rate test results will be different.

Any change in a major cost category in either the rate period years or the ensuing four years will change the test results.

Q. APAC examined how the calculation over the five years is made and tested whether or not it met APAC's criterion of "elimination of anomalies." Wolverton, WP-10-E-AP-01, at 18. APAC believes a more complex method seems more appropriate. Id. Please respond.

A. As discussed earlier, we are unaware of any statutorily required criterion to eliminate anomalies. As discussed above, we and APAC agree that an apparent purpose of including the four additional years is to mitigate the effects of anomalies; but mitigation is not the same as elimination. In addition, we consider APAC's example to be unrealistic in that it has the anomaly occurring in the third year of the 5-year rate test period. As noted previously, if there were to be a forecast of an anomalous year in the five-year 7(b)(2) rate test period, it is much more likely to be the first year. We agree with APAC that a simple average of the Program Case rates and the 7(b)(2) Case rates is too simplistic. We continue to believe that a method using the time value of money from the perspective of how BPA would value the money is the proper way to incorporate the different years' rates in the rate test. BPA's current method of discounting to the beginning of the rate period using BPA's borrowing rate accomplishes this goal.

Q. APAC tested the 5-year requirement by developing a simulation model that used a set of hypothetical BPA costs, unbifurcated BPA rates, and ASC levels over a nine-year period. Wolverton, WP-10-E-AP-01, at 19. In APAC's modeling, it chose to vary the results highly, independently growing and shrinking BPA costs and ASCs. Id. APAC claims that from these hypothetical, random levels, the Program Case and 7(b)(2) Case rates can be established for each year, and five-year combinations of the resulting triggers can be examined. Id. Please respond.

A. We have no comment on APAC's simulation model other than to acknowledge that changing major cost items will produce different rates. We note that in this portion of its testimony, APAC states that changes in ASCs and exchange loads that determine REP costs will have an effect on the unbifurcated PF rate and thus the results of the 7(b)(2) rate test. Earlier in its testimony, APAC stated there was a statutory requirement that the cost of the REP be excluded from the calculation of the rate test. Also, as discussed earlier, we continue to disagree with APAC's argument that there is a requirement that rate level anomalies need to be eliminated.

Q. The criterion APAC used to determine the correct method of combining rate test results for each year was to find the method of combining annual trigger results that smoothes the annual trigger data but at the same time minimizes the difference between the annual values and the combined trigger, as measured by least-squares statistical calculations. Wolverton, WP-10-E-AP-01, at 20. Please respond.

A. As stated earlier, the statutory directive to include four years beyond the rate period years is to ensure that the rate period 7(b)(2) rate test trigger in one rate case is similar to the rate test triggers in later rate cases, all else being equal. This is accomplished by reducing the weighting of an anomalous first-year rate difference between the Program Case and the 7(b)(2) Case. Also, smoothing the within-rate-case annual data is not necessarily a meaningful criterion; nor is minimizing the differences between the rate test period average difference and the annual differences between the Program Case and 7(b)(2) Case rates.

Discounting the two sets of rates by BPA's borrowing rate and then averaging the resultant discounted rates to get an average present value over the rate test period from the perspective of how BPA itself would value the rate revenues from both cases is a much more appropriate method. BPA's method has the advantage of levelizing the annual rates in a way that can be tied to BPA's financial situation; that is, using BPA's borrowing interest rate for the discounting in theory makes BPA indifferent between taking the discounted revenue now or the non-discounted revenue later. For the reasons just stated, the Implementation Methodology's direction to adjust the Program Case and 7(b)(2) Case rates using a BPA-centric financial time-value-of-money method before the calculation of the 7(b)(2) rate test trigger is superior to any statistical-based smoothing scheme proposed by APAC.

Q. APAC used its simulation model to test three methods of smoothing the five years of results; in the simulation, some trigger results were favorable to preference customers, and some were favorable to exchanging utilities. Wolverton, WP-10-E-AP-01, at 20. APAC claims its model evaluates errors caused by the averaging method and assesses the statistical impact in a search for the least deviation from annual values. Id. Please respond.

A. As discussed previously, APAC has missed the point of using the four additional years in the 7(b)(2) rate test. APAC also has statistical criteria that may be mathematically interesting but have no foundation in BPA finance. APAC's simple average example is not what BPA does or what APAC is proposing.

Q. Based on over 200 simulations and comparisons, APAC recommends that BPA switch to a method for calculation of the Trigger based on an inflation adjustment internal to the data for BPA costs and ASC levels. Wolverton, WP-10-E-AP-01, at 21. Please respond.

A. APAC's simulations do not show that BPA's current discounting method distorts the results. APAC's simulations and its proposal result in higher 7(b)(2) rate test triggers, as shown in its Exhibit 8 (8.5 for BPA's method, 9.2 for General Inflation, and 13.0 for Internal Inflation). Those higher triggers, if adopted by BPA, would result in lower rates paid by APAC's members. However, the current methodology of using BPA's borrowing rate as the discounting factor has the advantage of being tied to BPA's financial situation, along with the advantage of having been used since the inception of the 7(b)(2) rate test. APAC's number-smoothing criteria are not based on BPA's rate directives and provide no reason for BPA to change its long-standing discounting methodology.

Q. JP8 also addresses the method by which BPA discounts the Program Case and 7(b)(2) Case rates for purposes of calculating the rate test trigger. O'Meara et al., WP-10-E-JP8-01, at 7-8. JP8 proposes that BPA should use the rate of inflation to discount the Program Case and 7(b)(2) Case rates to the beginning of the rate period for purposes of calculating the rate test trigger. Id. JP8 claims that this methodology is more appropriate because BPA's rate projections are based on BPA's best-available forecasts of loads and costs expressed in nominal dollars. Id. As such, JP8 claims, there is no systematic bias in the projections, and the only adjustment needed for comparison is to ensure that all rates are expressed in equivalent dollars. Id. Please respond.

A. JP8 apparently does not argue against BPA using a time value of money discounting methodology. However, JP8 has confused the concepts of the "time value of money" and "real versus nominal dollars." The concept of the time value of money is based on the fact that money available at the present time is worth more than the same amount in the future. The difference is due to the potential earning capacity of an amount of money in hand today as compared to the same amount of money available at some future date. Therefore, any amount of money that could earn an interest rate is worth more the sooner it is received. For example, assuming that a 6.75 percent average BPA borrowing rate is the interest rate in question, $100 invested today would be worth $106.75 in one year ($100 multiplied by 1.0675). Conversely, $100 received one year from now is worth only $93.68 today ($100 divided by 1.0675). The forecast Program Case and 7(b)(2) Case rates for the rate period and the four ensuing years represent income to BPA to be received in those years. As described above, given the concept of the time value of money, income in some future year is worth less to BPA than income today. That difference in value has to do with the potential interest income if the money is in hand or the potential interest cost if the money will be available only at some future time. The current discounting methodology, which uses BPA's borrowing rate, makes BPA indifferent to when in the rate period (plus the ensuing four years) revenue from the rates is received. By contrast, JP8's suggestion that BPA simply use GDP deflators to put a series of annual nominal dollar rates in the real dollars of the current year is clearly not the same as using an interest earning rate to determine the time value of money.

Q. The OPUC proposes a change to how the 7(b)(2) rate test results are translated into REP benefits that should be provided for the rate period. Hellman et al., WP-10-E-PU-01, at 1-12. The OPUC notes that BPA's current methodology focuses on the level of costs that need to be excluded in order to provide rate protection for the public utilities required by Federal statute. Id. Please respond.

A. The OPUC is correct that BPA's current methodology focuses on the level of costs that need to be excluded from the public customers' rates in order to provide rate protection to those customers. We have become familiar with section 7(b)(2) in order to perform the implementation of the 7(b)(2) rate test. The plain language of section 7(b)(2) supports the current methodology:

> (2) After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that—
>
> (A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are—
>
> (i) served by the Administrator, and

(ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

(B) public body, cooperative, and Federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980, (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;

(C) no purchases or sales by the Administrator as provided in section 839c(c) of this title were made during such five-year period;

(D) all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were—

(i) purchased from such customers by the Administrator pursuant to section 839d of this title, or

(ii) not committed to load pursuant to section 839c(b) of this title,

and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and

(E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from—

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under this chapter

were not achieved.

The OPUC's description of BPA's current methodology comports with our understanding of the language in the Northwest Power Act.

Q. *The OPUC argues that using the current 7(b)(2) methodology can yield counterintuitive and unstable results, and, in OPUC's view, is inequitable in the context of the 7(b)(2) analysis. Hellman et al., WP-10-E-PU-01, at 2. The OPUC proposes a different approach, which is to look at the level of REP benefits that can be provided over the study period while still providing the 7(b)(2) rate test protection. Id. Please respond.*

A. Staff disagrees with the OPUC's contention that BPA's current methodology can produce counterintuitive, unstable, and inequitable results. BPA's current methodology calculates an average discounted rate test trigger over the rate period plus the ensuing 4 years. In the current rate case, that is a test period of 6 years. Therefore, the rate protection provided to the public customers is an average discounted rate protection over 6 years, and that protection is applied to the 2-year rate period. Just as the conduct of the section 7(b)(2) rate test in determining the amount of rate protection afforded BPA's preference customers is controlled by the language of the Northwest Power Act above, the methodology used to allocate that rate protection amount to other loads is controlled by the language of section 7(b)(3) of the Act:

> (3) Any amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers.

In this rate case, those supplemental rate charges derived from the protection afforded by the 7(b)(2) rate test, which is calculated over the 6-year rate test period, are applied only to the 2-year rate period loads. In this way, the rate test, as measured in this rate case, can affect the rates of only this rate period, FY 2010-2011. Similarly, the rate test in this rate case can affect the REP benefit calculation for only this rate period, FY 2010-2011. OPUC's analysis, as discussed below, makes the fundamental error of using the FY 2010-2011 rate case 7(b)(2) rate test to calculate REP benefits outside of the

FY 2010-2011 rate period. This fundamental error renders any conclusions drawn from OPUC's analysis seriously defective.

Q. The OPUC states that the approach in BPA's methodology is to identify the average level of costs to be excluded by taking the average difference between the discounted Program Case and 7(b)(2) Case rates. Hellman et al., WP-10-E-PU-01, at 2. The OPUC states that even in the instances where the 7(b)(2)-allowed REP benefits within the 7(b)(2) Study are relatively stable or even increasing, the current Implementation Methodology would significantly reduce the level of REP benefits provided in the rate period by way of the averaging of the discounted rate differences between the Program and 7(b)(2) Cases. Id. Please respond.

A. The OPUC misunderstands BPA's current 7(b)(2) methodology. The first apparent misunderstanding is that, while the FY 2010-2011 7(b)(2) rate test trigger is calculated using the Program Case and 7(b)(2) Case rates for the six-year period, the REP benefits are calculated for only the rate period. The OPUC proposes a different approach, which is to look at the level of REP benefits that can be provided over the six-year period. The OPUC proposes to look at the level of REP benefits for the FY 2012-2013 rate period and the FY 2014-2015 rate period, but calculated with the 7(b)(2) rate test trigger of the FY 2010-2011 rate case period.

The section 7(b)(2) rate test is conducted to determine the rate protection, if any, that should be afforded the PF Preference customers for the rate period. In so doing, the rate period PF rate is bifurcated into a rate period PF Preference rate and a rate period PF Exchange rate. It is inappropriate to use the FY 2010-2011 rate test to calculate PF Exchange rates to estimate the FY 2012-2013 rate period and FY 2014-2015 rate period REP benefits. It is also inappropriate to use these erroneously calculated future REP benefits to characterize the results of the current methodology as "counterintuitive and unstable."

Q. *The OPUC states that its analysis shows that the level of REP benefits that is assumed to be allowable, meaning that is meeting the 7(b)(2) protection requirements, is constant in each year at $250 million. Hellman et al., WP-10-E-PU-01, at 3. Yet REP participants do not receive $250 million in REP benefits. Id. Because the Implementation Methodology essentially uses the average level of costs excluded from PF Preference rates, residential REP benefits in the rate period are reduced from the amount determined to be an allowable amount under the rate test. Id. Please respond.*

A. The OPUC's argument uses its own definitions of rate protection and allowable REP benefits and a highly unrealistic numerical example. First, any particular level of REP benefits, even if it is constant over some period of time, cannot be defined as "meeting the 7(b)(2) rate protection requirements." The section 7(b)(2) rate test determines the amount of rate protection. The allowable REP benefits are a result of that rate protection, not the cause of the rate protection. Second, the OPUC describes the values in its analysis as discounted values. At a discount rate of about 6.75 percent per year used by BPA, if the discounted total REP costs were to grow from $350 million to $750 million in four years as shown in OPUC's analysis, a nominal growth rate of 29.2 percent per year would be necessary for the non-discounted REP costs. The discounted range of $350 million to $750 million is equal to a non-discounted range of $374 million to $1,040 million, assuming the 6.75 percent annual discount rate. By contrast, the non-discounted REP costs before 7(b)(2) in the Initial Proposal grow from $569 million in 2010 to $653 million in 2014, reflecting a nominal growth rate of 3.5 percent per year. The OPUC's attempt to prove methodological instability relies on data that is so unrealistic, it renders the example unhelpful.

Q. *The OPUC states it can demonstrate the instability of BPA's REP benefit calculation for the rate period using BPA's RAM2010 model. Hellman et al., WP-10-E-PU-01, at 4. Please respond.*

A. The analyses provided by the OPUC do contain values found in the RAM2010 model used to calculate Initial Proposal rates. However, as stated earlier, because the REP benefit amounts for the years FY 2012-2015 are calculated with the 7(b)(2) rate test trigger from the FY 2010-2011 rate period, they do not accurately reflect what the REP benefits will be in those years. The RAM2010 model happens to calculate rates and other related values for years from FY 2010 to FY 2019. For the Initial Proposal, the rates calculated for the FY 2010 to FY 2015 rate test period are used to calculate the FY 2010-2011 7(b)(2) rate test trigger. The FY 2010-2011 7(b)(2) rate test trigger is the only trigger calculated in the current version of the model, and that trigger amount is then used to determine the FY 2010-2011 PF Exchange rate and later the estimate of REP benefits for FY 2010-2011.

The estimates of REP benefits for FY 2012-2015 shown in the model, calculated using the FY 2010-2011 trigger, are for display purposes only and are not used in BPA ratemaking. Therefore, any analysis that compares the FY 2010-2011 REP benefits with the displayed FY 2012-2015 benefits will be faulty and not useful. To compare forecasts of REP benefits for the FY 2010-2015 time period, three separate 7(b)(2) rate tests would need to be conducted to calculate three different 7(b)(2) rate test triggers and three different PF Exchange rates: one for the FY 2010-15 test period, one for the FY 2012-17 test period, and one for the FY 2014-19 test period. Only then could one compare 6 years of REP benefit amounts. OPUC did not conduct such an analysis, and that failure renders its conclusions suspect.

Q. Can an estimate be made of what a properly conducted analysis of the REP benefits from FY 2010 to FY 2015 would show?

A. We can use our professional experience to make some estimates about trends in the future without actually conducting an additional two 7(b)(2) rate test calculations. Generally, if the exchanging utilities’ costs increase into the future faster than BPA’s costs, the 7(b)(2) rate test trigger will increase and the PF Exchange rate will increase, all else being equal. This higher PF Exchange rate relative to participants' ASCs will exert a downward pressure on REP benefits.

In the current rate case, participants' ASCs are increasing over time faster than BPA's costs, and it is reasonable to expect that the FY 2012-2013 rate test trigger will be larger than the current FY 2010-2011 rate test trigger. Therefore, it is reasonable to expect that, given that higher trigger, the REP benefits for FY 2012-2013 will be lower than those displayed in the OPUC's table. Conversely, if the exchanging utilities' ASCs were to decrease over time relative to BPA's costs, it is reasonable to expect that the 7(b)(2) rate test trigger would be lower, the PF Exchange rate would be lower, and the REP benefits would be higher, all else being equal. Without conducting the analysis, the actual amounts of REP benefits under these two scenarios is uncertain, but the directionality described is logical and intuitive.

Q. For illustrative purposes, OPUC ran two alternative cases. Hellman et al., WP-10-E-PU-01, at 5-6. Please respond.

A. As discussed above, the OPUC's analysis is faulty because the FY 2012-2015 REP benefits are calculated using the wrong 7(b)(2) rate test trigger, the FY 2010-2011 rate test trigger. Also as discussed above, with declining ASCs relative to BPA's costs, one would expect a smaller 7(b)(2) rate test trigger, a lower PF Exchange rate, and larger REP benefits than the OPUC shows in its analysis.

Q. The OPUC notes that BPA has expressed concern about the variability of rate period net REP benefits because of changes in out-year ASC trajectory assumptions. Hellman et al., WP-10-E-PU-01, at 7. Please respond.

A. The BPA workshop that the OPUC cites was to provide information to interested parties, and the examples were presented to show that the 7(b)(2) rate test, by design, calculates an average protection amount over the rate period plus the four ensuing years, while applying that rate protection to only the rate period year(s). The workshop information showed that different out-year ASCs would logically produce different rate period REP benefits.

Q. *The OPUC recommends that focus not be placed on the level of REP costs that must be excluded from PF rates and instead focus on the level of residential benefits that can be provided to residential and small-farm customers while still providing preference customers the statutorily required rate protection. Hellman et al., WP-10-E-PU-01, at 7. Instead of moving up protection amounts for out-year changes through the trigger rate mechanism, the OPUC recommends that focus be placed on the REP benefits that are available to exchanging customers over the entire study period. Id. Please respond.*

A. The BPA statements that OPUC cites were made in the context of finding a long-term, stable basis of providing REP benefits to REP participants. However, such a desire does not mean that section 7(b)(2) can be arbitrarily re-interpreted to shift its focus from rate protection for preference customers to providing REP benefits. Any long-term solution to stabilizing REP benefits must be consistent with statute. We must continue to follow the controlling ratemaking statutes provided by Congress, as set forth in the Legal Interpretation and Implementation Methodology, regardless of regional discussions concerning the stability of REP benefits. Furthermore, due to flaws in its analysis, the OPUC has not demonstrated that future REP benefits will not be stable.

Q. *The OPUC states that the Initial Proposal includes a table appearing in Pub Exchange tab of RAM2010. Hellman et al., WP-10-E-PU-01, at 8. Under one of OPUC's alternative approaches, the rate period net REP benefit would equal the average net REP benefits across the study period, FY 2010 through FY 2015, for all the investor-owned utilities in aggregate. Id. Using a straight average approach would yield an average of $313,690. Id. Please respond.*

A. Again, the OPUC is using its faulty analysis and values from RAM2010 that are not used in ratemaking. These values are not realistic for the reasons described previously. Using an average for two appropriately calculated numbers and four inappropriately calculated numbers is not useful.

Q. The OPUC analysis displays OPUC's alternative approaches. Hellman et al., WP-10-E-PU-01, at 9. Exhibit WP-10-E-PU-3 provides alternative approaches to calculating rate period REP benefits. Id. Please respond.

A. Again, OPUC is using results from a faulty analysis, and its conclusions are therefore not adequately supported.

Q. The OPUC states that its proposal does not produce counterintuitive results. Hellman et al., WP-10-E-PU-01, at 10-11. Please respond.

A. Again, as discussed above, the OPUC analysis is faulty, and any conclusion from that faulty analysis has little value. The OPUC's outyear REP benefit calculation is incorrect and uses the wrong 7(b)(2) rate test trigger.

Q. The OPUC recommends its Alternatives A and C. Hellman et al., WP-10-E-PU-01, at 11. OPUC's Alternative A is simplest in calculation and reflects the average level of REP benefits projected to be paid over the study period. Id. OPUC's Alternative C is somewhat more stable over various scenarios and reflects equal weighting of the rate period with the rest of the 7(b)(2) study period. Id. Please respond.

A. Picking between OPUC's alternatives, all of which are based on faulty analysis, is not useful.

Q. The OPUC states that the OPUC-identified alternatives do not make changes to BPA's 7(b)(2) analysis other than ASC trajectories. Hellman et al., WP-10-E-PU-01, at 11. The OPUC states that it made no changes to the BPA 7(b)(2) modeling assumptions, which include financing benefits, resource stack, treatment of conservation, DSI loads, *and treatment of surplus sales, or to any other modeling of the 7(b)(2) Case. Id. Please respond.*

A. Again, we will rely on the rate directives in the statutes, as set forth in the Legal Interpretation and Implementation Methodology, and not on the faulty analysis provided by the OPUC.

Q. The OPUC states the alternatives proposed by the OPUC are consistent with the 7(b)(2) rate directives. Hellman et al., WP-10-E-PU-01, at 12. Please respond.

A. Ultimately, whether the OPUC's alternatives are consistent with the section 7(b)(2) rate directives and whether the alternatives ensure rate protection as mandated by the Northwest Power Act are legal issues that can be addressed in parties' briefs and BPA's Records of Decision. We believe the OPUC analysis is built on faulty assumptions and logic. OPUC has not demonstrated whether its goal of stable REP benefits is or is not achieved by BPA's implantation of section 7(b)(2). The RAM2010 was not designed for the type of analysis that OPUC is trying to perform. While it may be a worthy goal, stable REP benefits, in our opinion, are not the guiding principle of the section 7(b)(2) rate test.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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EXHIBIT A

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(AUTHENTICATED COPY)

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

OFFICE OF THE ADMINISTRATOR

In reply refer to: PKL

February 27, 1987

Contract No. DE-MS79-86BP92300

Mr. J. Chiara, Benton Rural Electric Association, Prosser, WA
Mr. J.P. Ramseyer, Blachly-Lane County Coop., Eugene, OR
Mr. L. Powell, Central Electric Coop., Redmond, OR
Mr. G. King, Clearwater Power Company, Lewiston, ID
Mr. J.F. Mayse, Consumers Power, Inc., Corvallis, OR
Mr. E. Schlender, Coos-Curry Electric Coop., Inc., Port Orford, OR
Mr. H. Crinklaw, Jr., Douglas Electric Coop., Inc., Roseburg, OR
Mr. C. Wickham, Fall River Electric Coop., Ashton, ID
Mr. D. Heitman, Lincoln Electric Coop., Davenport, WA
Mr. L.R. Greene, Lost River Electric Coop., Mackay, ID
Mr. R. Hanson, Lower Valley Power & Light, Afton, WY
Mr. G. Gardiner, Raft River Electric Coop., Malta, ID
Mr. R.N. Dorran, Umatilla Electric Coop., Hermiston, OR
Mr. D. Piper, Pacific Northwest Generating Company, Portland, OR

Gentlemen:

Pacific Northwest Generating Company (PNGC) contemplates executing a long-term power sales agreement in the future for its share of the output of the Boardman Plant. Bonneville Power Administration (Bonneville) and PNGC intend to enter into a long-term agreement which will provide services similar to those provided under the previous services agreement, Contract No. DE-MS79-86BP92154.

Prior to the effective date of any long-term contract for the sale of Project Output, PNGC may enter into short-term sales of Project Output with entities within or outside of the Pacific Northwest. In order to facilitate any such sale, PNGC and its members (Utilities) desire that Bonneville act as agent for the scheduling of the Project.

Bonneville and each of the Utilities have separately entered into a Power Sales Contract as specified in Exhibit C which provides for the sale of power at Bonneville's Priority Firm Rate to meet each Utility's firm requirements for power.

The parties to this Agreement desire to provide for displacement of Project Output with energy at such times as Bonneville, at its sole discretion, determines that it has nonfirm energy or surplus firm power available at an economical rate as mutually agreed by PNGC and Bonneville.

Therefore, PNGC, the Utilities, and Bonneville agree to operate in accordance with the following terms and conditions:

1. Term.

   This Agreement shall be effective, upon execution by all parties, as of 2400 hours on June 30, 1986 (Effective Date). This agreement shall terminate on the earlier of the effective date of a long-term agreement which replaces this Agreement, or 30 days after receipt of a termination notice given by either PNGC and the Utilities or Bonneville. All parties agree that any services, power, or energy provided by Bonneville between the Effective Date and the date this Agreement is executed are subject to the terms and conditions of this Agreement. All liabilities accrued hereunder shall be preserved until satisfied.

2. Definitions.

   (a) "Assured Delivery" means Intertie transmission service provided by Bonneville under its Intertie Access Policy in effect at the time.

   (b) "Point of Delivery" means the point in the Government's Slatt Substation where the Boardman Plant 500 kV transmission line is connected or other points as the parties may agree to.

   (c) "Project" means PNGC's 10 percent ownership interest in the Boardman Plant consisting of a site, a generating unit, and related transformation and transmission facilities as defined in an Agreement for Construction, Ownership, and Operation of the No. 1 Boardman Station on Carty Reservoir dated October 15, 1976.

   (d) "Project Output" means (1) the electric power which can be produced by the Project less project station service requirements and losses from the Project to the Point of Delivery; or (2) electric power made available by one or more owners of the Boardman Plant in lieu of electric power produced at the Project.

   (e) "Sales Agreement" means an agreement between PNGC and a party or parties within or outside the Pacific Northwest providing for the firm sale of Project Output.

   (f) "Purchasing Party" means the party or parties which purchase Project Output under a Sales Agreement.

   (g) "Utility Project Share" means each Utility's share of the Project Output as listed in Exhibit C.

3. <u>Exhibits and Interpretations</u>.

(a) The following exhibits are attached hereto and by this reference made a part of this Agreement: Exhibit A (Bonneville's 1985 Wholesale Power Rate Schedules); Exhibit B (General Rate Schedule Provisions (GRSP's)); Exhibit C (Utilities' Project Shares and Power Sales Contract Numbers); and Exhibit D (Determination of the Service Charge).

(b) The rights and obligations of the parties hereunder shall be subject to, and are governed by, this Agreement. The headings used in this Agreement are for convenient reference only, and shall not affect the interpretation of this Agreement.

4. <u>Sales Agreements Requiring Use of PNW-PSW Intertie (Intertie)</u>.

PNGC and the Utilities understand and agree that requests for Assured Delivery will be evaluated on a case-by-case basis for conformance with Bonneville's Intertie Access Policy then in effect. Assured Delivery for Sales Agreements shall be solely determined by Bonneville.

5. <u>Scheduling of Project Output</u>.

The Utilities and PNGC designate Bonneville as their agent for the purpose of scheduling Project Output from the Portland General Electric Company (PGE) during the term of this Agreement. Bonneville shall request Project Output only to the extent necessary to fulfill PNGC's Sales Agreement obligations, as limited by section 4 above.

6. <u>Station Service</u>.

Bonneville shall make available at Pacific Power & Light's Dalreed Substation or the Government's Slatt Substation such amounts of power as are necessary to meet PNGC's obligations for Project start-up and station service during those periods when the Project is not generating. Such power shall be billed, as specified in section 10 below, at the Priority Firm Power Rate under the Utilities' Power Sales Contracts.

7. <u>Displacement of Project Output</u>.

On hours when Bonneville determines that nonfirm energy or surplus firm power is available for displacing Project Output, and to the extent requested by PNGC, Bonneville shall schedule, subject to the limitations of section 4 above, such nonfirm energy or surplus firm power to the Purchasing Party, rather than schedule Project Output pursuant to section 5. Any such nonfirm energy or surplus firm power requested by PNGC shall be billed as specified in section 10. Bonneville shall make such nonfirm energy or surplus firm power available at the Point of Delivery.

8. Notification.

Bonneville shall notify PNGC, as soon as practicable, that Bonneville has nonfirm energy or surplus firm power available to displace Project Output, or that nonfirm energy or surplus firm power used to displace Project Output has been restricted.

9. Records.

(a) Bonneville shall keep records of the following:

(1) the hourly amounts of nonfirm energy delivered to the Point of Delivery;

(2) the hourly amounts of surplus firm power delivered to the Point of Delivery;

(3) the daily and hourly amounts of power and energy requested by each Purchasing Party;

(4) the actual hourly amounts of power and energy scheduled to each Purchasing Party;

(5) the hourly amounts of actual Project generation;

(6) the hourly amounts of power provided in lieu of generation from the Project; and

(7) the hourly amounts of power delivered by Bonneville for start-up and station service.

(b) At PNGC's request, Bonneville shall provide information concerning the status and scheduling of the Project, and the schedules, preschedules, and other information submitted to Bonneville by any Purchasing Party.

(c) Bonneville shall send such information listed above to PNGC for each month as soon as practicable after end of each calendar month during the term of this Agreement.

10. Payment.

(a) The Utilities shall pay for all nonfirm energy which Bonneville has provided for the displacement of Project Output at the applicable rate specified in the NF-85 rate schedule or its successor. Each Utility shall purchase the portion of such nonfirm energy equal to the product of the total amount of nonfirm energy made available in each month and the Utility's Project Share.

(b) The Utilities shall pay for all surplus firm power which Bonneville has made available at the applicable rate under the SP-85 rate schedule or its successor. Each Utility shall purchase the portion of such surplus firm power equal to the product of the total amount of surplus firm power made available in each month and the Utility's Project Share.

(c) Each Utility shall pay for the amount of station service, provided pursuant to section 6, equal to the product of the total amount of power made available and the Utility's Project Share.

(d) Each Utility shall pay, as compensation for scheduling and management services provided by Bonneville, an amount calculated pursuant to Exhibit D and applied to each Utility's Project Share.

Bonneville's average costs for the operating year and the amount of Federal system firm energy load carrying capability used in Exhibit D may be estimates, in which case monthly service charges shall be calculated and billed using the estimated amounts. At such time as final amounts are available, Bonneville shall recalculate the service charges and corresponding adjustment shall be made to the Utilities' power bills under their respective Power Sales Contracts to account for amounts previously overbilled or underbilled.

(e) For power, energy, and services provided by Bonneville under this Agreement, Bonneville shall submit the Utilities' bills to PNGC. Each Utility hereby authorizes PNGC to pay Bonneville on its behalf for such power, energy, and services provided by Bonneville. Bonneville shall accept payment from PNGC for the account of each Utility for power, energy, and services provided under this Agreement.

(f) Payment by PNGC shall be in accordance with Exhibit B.

11. Execution by Counterpart.

This Agreement shall be executed in a number of counterparts and shall be deemed to constitute a single document with the same force and effect as if all the parties hereto, having signed a counterpart, had signed all other counterparts. Each party shall deliver a signed counterpart to Bonneville, which shall prepare a conformed copy and deliver the same to each party. This Agreement shall become effective as to each signing party on the Effective Date once counterparts have been signed by all Utilities, PNGC, and Bonneville.

12. Approval of Agreement.

The parties agree that this Agreement shall not become binding on the parties if it is not approved by the Rural Electrification Administration. If such approval is given, the Agreement shall be effective as of the Effective Date.

13. Assignment.

This Agreement shall not be assigned by any party hereto without the written consent of all other parties hereto which consent shall not be unreasonably withheld.

14. Additional Compensation Due Bonneville for Scheduling and Management Services.

During Operating Years 1984-85 and 1985-86, the Utilities paid Bonneville an estimated charge of 0.144 mills/kWh as compensation for scheduling and management services, using the methodology described in Exhibit D. The final charges for those two Operating Years have been determined, resulting in the following adjustments:

Operating Year	Project Output Managed (KWh)	Estimated Charge (mills/KWh)	Amount Billed
1984-85	23,307,000	0.144	$ 3,356
1985-86	109,151,000	0.144	$15,718
		Total =	$19,074

Operating Year	Project Output Managed (KWh)	Final Charge (mills/KWh)	Amount Which Should Have Been Billed
1984-85	23,307,000	0.168	$ 3,916
1985-86	109,151,000	0.166	$18,119
		Total =	$22,035

Therefore, the net amount owed to Bonneville by the Utilities is $2,916. The Utilities agree to pay Bonneville this amount, which shall be billed in accordance with the terms of subsection 10(e).

If the preceding provisions are acceptable, please sign and return four copies to Bonneville with the required authorizing resolutions containing original signatures.

Sincerely,

/s/ James J. Jura

Administrator

ACCEPTED:
PACIFIC NORTHWEST GENERATING COMPANY

By /s/ David E. Piper

Title General Manager

Date June 9, 1987

ACCEPTED:
CLEARWATER POWER COMPANY

By /s/ Kenneth Summers

Title President

Date 3-25-87

ACCEPTED:
BENTON RURAL ELECTRIC ASSOCIATION

By /s/ Vonard R. Bedker

Title President

Date 3/24/87

ACCEPTED:
CONSUMERS POWER INC.

By /s/ Charles Hecht

Title President

Date March 25, 1987

ACCEPTED:
BLACHLY-LANE COUNTY COOPERATIVE ELECTRIC ASSOCIATION

By /s/ Everett Falk

Title President

Date 3-24-87

ACCEPTED:
COOS-CURRY ELECTRIC COOPERATIVE, INC.

By /s/ L. Monte Lund

Title President

Date 3/27/87

ACCEPTED:
CENTRAL ELECTRIC COOPERATIVE, INC.

By /s/ Donald W. Miltenberger

Title President

Date April 16, 1987

ACCEPTED:
DOUGLAS ELECTRIC COOPERATIVE, INC.

By /s/ Marion A. Rentz

Title President

Date 4/22/87

ACCEPTED:
FALL RIVER RURAL ELECTRIC
COOPERATIVE, INC.
By /s/ Gale A. Reed
Title President
Date

ACCEPTED:
LOWER VALLEY POWER & LIGHT, INC.
By /s/ James Little
Title President
Date 3/26/87

ACCEPTED:
LINCOLN ELECTRIC COOPERATIVE, INC.
By /s/ Ted Zeimantz
Title President
Date 3-27-87

ACCEPTED:
RAFT RIVER RURAL ELECTRIC
COOPERATIVE, INC.
By /s/ Stanley A. Spencer
Title President
Date 4-23-87

ACCEPTED:
LOST RIVER ELECTRIC COOPERATIVE, INC.
By /s/ C. Boyd Lambert
Title President
Date April 20, 1987

ACCEPTED:
UMATILLA ELECTRIC COOPERATIVE
ASSOCIATION
By /s/ Jerry E. Myers
Title President
Date April 22, 1987

(AUTHENTICATED COPY)

CERTIFICATION

I, Douglas Hanlon, Electrical Engineer, Marketing Branch, Division of Customer Service, Bonneville Power Administration, do hereby certify that the contract to which this certificate is attached is a true, complete and conformed composite copy of Contract No. DE-MS79-86BP92300, which provides, among other things, for BPA to schedule PNGC's share of the Boardman project output from PGE, and for BPA to displace Boardman with nonfirm energy when such energy is available at economic rates. Signed counterpart originals are on file with the Bonneville Power Admininstration, each signed by the parties thereto.

/s/ Douglas Hanlon
Douglas Hanlon, Electrical Engineer
Marketing Branch
Division of Customer Service

Date July 1, 1987

(WP-PKL-1400b)

Exhibit C
Contract No. DE-MS79-85BP92300
PNGC and Member Utilities
Effective at 2400 hours on
June 30, 1986

<u>Utilities' Project Share</u>
<u>and</u>
<u>Power Sales Contract Number</u>

Member Utility	Power Sales Contract No. 1/	Percentage of PNGC's Total 10% Share of Boardman Plant 2/
Benton Rural Electric Association	DE-MS79-81BP90519	9.810
Blachly-Lane County Cooperative Electric Association	DE-MS79-81BP90821	3.500
Central Electric Cooperative, Inc.	DE-MS79-81BP90522	10.200
Clearwater Power Company	DE-MS79-81BP90523	5.200
Consumers Power, Inc.	DE-MS79-81BP90527	11.232
Coos-Curry Electric Cooperative, Inc.	DE-MS79-81BP90528	12.000
Douglas Electric Cooperative, Inc.	DE-MS79-81BP90529	5.000
Fall River Rural Electric Coop., Inc.	DE-MS79-81BP90532	3.200
Lincoln Electric Cooperative, Inc.	DE-MS79-81BP90544	2.740
Lost River Electric Cooperative, Inc.	DE-MS79-81BP90545	2.478
Lower Valley Power & Light, Inc.	DE-MS79-81BP90546	10.000
Raft River Rural Electric Coop., Inc.	DE-MS79-81BP90557	5.317
Umatilla Electric Coop. Association	DE-MS79-81BP90566	19.323

1/ Each Utility's power sales contract with Bonneville, referenced above by contract number, is by that reference made a part of this Agreement.

2/ Each Utility's "Percentage of PNGC's total 10% Share of Boardman Plant" is as it appears in Exhibit A (Boardman Allocation) of the "Power Sales Contract - Revised" which is executed between PNGC and each Utility. PNGC shall notify Bonneville as soon as practicable in the event of any change in any utility's percentage. Bonneville shall then revise this exhibit to reflect such change and furnish PNGC and each of the Utilities with such revised exhibit.

(WP-PKL-1641c)

DETERMINATION OF THE SERVICE CHARGE

(For Management of Project Output)

(Capitalized terms not defined herein are as used in the Pacific Northwest Coordination Agreement)

1. Basic Assumptions.

(a) Bonneville will provide management services as outlined below for the Project Output. Such services will result in an increase in the operational requirements of the Federal System.

(b) The increase in Federal System costs associated with operating, scheduling, dispatching, and controlling an incremental increase in Federal System generating resources will be difficult to determine, as there are many interrelated factors that can combine to cause an incremental increase in such costs for Federal System load control.

(c) Derivation of the service charge will, consequently, be based on the Government's average costs of operating, scheduling, dispatching, and controlling Federal System power.

(d) Such Federal System average costs will be allocated uniformly to each kilowatthour of Federal System firm energy for the Operating Year.

(e) Operating, scheduling, dispatching, and controlling of the Federal System by Bonneville shall exclude Bonneville's substation operation activities and Bonneville's other area operation and maintenance activities. Emphasis will be on control of the Federal System through scheduling and dispatching activities of Bonneville.

2. Determination of the Average Costs of Scheduling and Dispatching Federal System Power for an Operating Year.

Procedure. Bonneville shall list the operating year costs of those facilities and functions which collectively comprise Bonneville's system costs of scheduling and dispatching Federal System power (Average Costs). Such listing shall include the following:

(a) System operations costs associated with Bonneville's control of the Federal System through scheduling and dispatching, including but not limited to:

(1) supervising main grid operations and dispatching;

(2) providing for dispatching outages, clearances, other switching, and the communications link;

(3) making system operational studies and analyses;

(4) providing for operation and maintenance of control facilities at the Dittmer Control Center;

(5) providing for operation of computers dedicated to system control and data acquisition; and

(6) determining general costs such as employee benefits, travel, materials, and supplies;

(b) Power supply costs associated with Bonneville's control of the Federal System through scheduling and dispatching, including but not limited to:

(1) supervision of power supply and power scheduling activities;

(2) providing for direct scheduling of power and water releases; negotiating with interconnected utilities for exchange of power, and scheduling of power over the Pacific Northwest-Pacific Southwest intertie;

(3) forecasting of water and stream flows using hydrometeorological techniques and procedures and the hydrometeorological network; and

(4) preparing 30 day, seasonal, critical period, and other plans of operation;

(c) Dittmer Control Center costs related to amortization of equipment used in system operation and power supply activities; and

(d) The administrative portion of general overhead costs including management, secretarial and clerical activities, and the use of general equipment and facilities.

(e) A summary of the Average Costs for the Operating Year.

Summary for Operating Year 1986-87

Item (a)	7,079,800 1/
Item (b)	2,572,100 1/
Subtotal [(a)+(b)]	$9,651,900
Item (d) [36.05% of (a)+(b)]	$3,479,510
Item (c)	1,898,964
TOTAL [(a)+(b)+(c)+(d)]	$15,030,374

3. Calculation of Bonneville's Service Charge per Kilowatthour of Federal System Firm Energy (Service Charge/kWh).

Procedure. Bonneville shall make the following calculation of Service Charge/kWh for Operating Year 1986-87: Divide Bonneville's Average Costs for the Operating Year by the Federal System firm energy load carrying capability (FELCC), for the year:

$15,030,374 ÷ 80,478,996,000 kWh = 0.187 mills/kWh

4. Calculation of Bonneville's Service Charge to the Utility for a Month.

Procedure. Bonneville shall make the following calculation of the Monthly Service Charge for each Utility following each month: Multiply Bonneville's Service Charge/kWh for the Operating Year (from section 3 of this Exhibit) by the kWh of firm energy managed pursuant to this Agreement during such month and by each Utility Project Share as listed in Exhibit C.

Calculation for a Month using 1986-87 Data

For each month during the period July 1, 1986 to June 30, 1987:
0.187 mills/kWh x __________ kWh 2/ = $_________ month.

For each Utility:
$________/ x Utility Percentage Share = $____/Utility/month

1/ From start of year Budget Form 408 for Systems Operations and Power Supply Costs.

2/ The amount of kilowatthours each month will be determined at the end of each billing month as determined by Bonneville and shall equal the total kilowatthours scheduled by Bonneville pursuant to section 5 during such month.

(WP-PKL-1641c)

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EXHIBIT B

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PMCG AUG 11 1989

Mr. David E. Piper, General Manager
Pacific Northwest Generating Company
500 NE. Multnomah, Suite 1480
Portland, Oregon 97232-2044

Dear Mr. Piper:

This is to acknowledge that the Bonneville Power Administration (BPA) has received each Pacific Northwest Generating Company member's request to remove its 5(b)(1)(B) contractual Boardman resource from each member's Firm Resource Exhibit (FRE) effective July 1, 1990, and for all subsequent years pursuant to section 12(b)(9) of the Power Sales Contract. The resource is currently listed as a 5(b)(1)(B) nonhydroelectric resource which is to serve load beginning July 1, 1990. This change would be made on the next FRE submitted by the utilities, due by January 1, 1990.

BPA will review the members' requests and contact you if we determine that there is a limitation on their ability to withdraw the resource. BPA's decision will be forwarded to you on their behalf by September 1 as required by section 12(b)(9). If the utilities have any questions or concerns, please ask them to contact their local Area or District Office.

Sincerely,

/S/ LK

Lawrence E. Kitchen, Chief
Power Contracts Branch

SEGFurst:sgf:3555 8/4/89 (VS6-PMCG-5722b)

cc:
J. Luce - APP
E. Arnold - DRER
W. Pollock - P
D. Metcalf - PM
C. Combs - PMCG
A. Holm - PSPC
Area Power Managers - LC, TC, UC, WC
Official File - PM 12-11-2
T. Miller - APP
T. Scanlon - DRES
J. Curtis - P
L. Kitchen - PMC
S. Garifo Furst - PMCG
B. Hoffman - RPSE
District Managers - LG, UM, UW, WL, WI
S. Melton - PM

PMCG

AUG 3 0 1989

Mr. David E. Piper
General Manager
Pacific Northwest Generating Company
500 NE Multnomah, Suite 1480
Portland, Oregon 97232-2044

Dear Mr. Piper:

This is to notify you that the Bonneville Power Administration (BPA) has approved each Pacific Northwest Generating Company (PNGC) member's request to remove the 5(b)(1)(B) contractual Boardman resource from their Firm Resource Exhibit (FRE) effective July 1, 1990 and for all subsequent years pursuant to section 12(b)(9) of the Power Sales Contract. This change shall be made on the next FRE submitted by the utilities which is due by January 1, 1990.

There is no immediate limitation on the members' ability to withdraw the resource since the current publication of BPA's loads and resources identifies a federal resource surplus through at least the seventh year of the FRE. However, any future requests by members to withdraw resources pursuant to section 12(b)(9) may be denied as BPA's load-resource situation changes and BPA publishes its revised load-resource position.

We look forward to receiving PNGC members' FRE updates later this year. If the utilities have any questions or concerns, please ask them to contact their local Area or District Office.

Sincerely,

(Sgd.) JAMES H. CURTIS

FOR Walter E. Pollock
Assistant Administrator
for Power Sales

SEGFurst:sgf:3555 8/4/89 (VS6-PMCG-5722b)

cc:
T. Miller - APP
M. Federovich - DRE
T. Scanlon - DRES
S. Melton - PM
C. Combs - PMCG
A. Holm - PSPC
Area Power Managers - LC, TC, UC, WC
Official File - PM 12-11-2
J. Yocom - DSA
E. Arnold - DRER
J. Curtis - P
D. Metcalf - PM
S. Garifo Furst - PMCG
B. Hoffman - RPSE
District Managers - LG, UM, UW, WL, WI

EXHIBIT C

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From: Tyran Gardner [TGardner@pngcpower.com]
Sent: Tuesday, June 17, 2008 7:47 AM
To: Hyde,Jeremy Z - PFB-6
Subject: RE: List or PRC Members
Hey-no problem.

Tyran Gardner
Administrative Assistant
503.288.1234 Office
503.288.7580 Direct
360.608.5941 Mobile
503.288.2334 Fax

PNGC Power 711 NE Halsey, Portland, Oregon, 97232-1268 www.pngcpower.com

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From: Hyde,Jeremy Z - PFB-6 [mailto:jzhyde@bpa.gov]
Sent: Monday, June 16, 2008 4:00 PM
To: Tyran Gardner
Subject: RE: List or PRC Members

Thanks!

From: Tyran Gardner [mailto:TGardner@pngcpower.com]
Sent: Monday, June 16, 2008 3:58 PM
To: Hyde,Jeremy Z - PFB-6
Cc: Kevin Watkins; Kathi VanderZanden
Subject: List or PRC Members

List of PRC Members

Benton REA
Blachly-Lane
Central Electric
Clearwater Power
Consumers Power
Coos-Curry
Douglas
Fall River
Lost River
Lower Valley
Raft River
Umatilla Electric
West Oregon

If you have any additional questions- feel free to contact us.

Thanks,

Ty

Tyran Gardner
Administrative Assistant
503.288.1234 Office
503.288.7580 Direct
360.608.5941 Mobile
503.288.2334 Fax

PNGC Power 711 NE Halsey, Portland, Oregon, 97232-1268 www.pngcpower.com

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