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Via Electronic Mail

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Re: Comments on BPA's Power Function Review II Draft Closeout Report

Dear Mr. Norman:

As the second phase of the Power Function Review process (PFR II) approaches its end, PPC would like to offer some observations and comments for your review, based on your draft closeout report issued on April 4. PPC has again coordinated the responses of a number of groups that have been following this process. We found the PFR II process to be fair, open, cooperative, and creative, and we were encouraged by the level of commitment of all parties to share and understand information on BPA's cost drivers. We especially want to thank you, Michelle Manary, Nita Burbank, and many others for your efforts in making PFR II a constructive process. Further, building on the PFR II experience, we hope to meet more regularly with representatives from the Corps of Engineers (Corps), Bureau of Reclamation (Bureau), EnergyNorthwest (EN), and the Northwest Power and Conservation Council (Council) to deepen our understanding of their budgets and their relation to BPA's budget.

Our sincere appreciation of the PFR II process, and of many of the cooperative ideas and actions arising out of that process, does not mean we agree with *all* of the results of the process. In that regard, as you draft your final closeout report, we urge you and BPA's sister-agencies to consider the following:

SUMMARY OF RECOMMENDATIONS

- **Extend amortization for conservation investments to 15 years.**
- **Extend amortization for F&W investments to greater than the minimum of 15 years.**
- **Inform customers of EN capital investment plans well-prior to final decision.**
- **Modestly increase forecasted output of Columbia Generating Station (CGS).**
- **Implement the hydro-benchmarking study and associated savings.**
- **Shift F&W funds from R, M & E to direct-benefit projects.**
- **Do not exceed $40 million in DSI benefits.**
- **Accelerate implementation of EPIP Phase One and reduce Internal Operations costs by an additional $4 million/year.**
- **Adjust conservation target by incorporating utility-funded projects, as appropriate.**
- **Remove Fourmile Hill project from this rate period, model the facilitation budget through NORM, and initiate a new facilitation funding process.**
- **Include customers in the Council's budget-planning process.**
- **Initiate on-going examination of forecasted budgets, with appropriate customer participation.**

COMMENTS AND RECOMMENDATIONS

A. Capital Cost Recovery

1. Extend amortization for conservation investments to 15 years. In general, we encourage BPA to match debt life with the life of the investment because this principle comports with sound business practices and better matches the recovery of costs from those that benefit from an asset. BPA has pointed to the Council's study, which found a median of a 15-year asset life for conservation investments installed after FY06. Accordingly, we recommend that BPA adopt a 15-year amortization period for its capitalized conservation investments, instead of the 5-year period assumed in the draft closeout report. Although this change does not significantly affect rates in the near term, after 2011 rates will be modestly relieved. Further, this change will make the amortization period comport more closely with the 20-year amortization period assumed for conservation before the new policy of debt financing over 5 years went into effect.

2. Extend amortization for F&W investments to greater than the minimum of 15 years. Similarly, we believe BPA should expand the assumed amortization period for Fish and Wildlife investments because using the 15-year period seems to reflect only the minimum life associated with these investments. A longer period should be assumed in order to reflect the average life of all the capitalized Fish and Wildlife investments in BPA's direct program

3. Inform customers of EN capital investment plans well-prior to final decisions. We would like to continue to be informed of discussions with EN about the wisdom of the capital improvements proposed for the FY07-09 period. The region helped the EN Executive Board make an informed decision regarding the proposal to extend the outstanding CGS debt past 2018 based on the costs and benefits of the proposal. We see this model as one to follow for future CGS-related debt and capital decisions.

B. Modestly increase forecasted output of Columbia Generating Station (CGS).

The operating costs of CGS (at 9% of BPA costs) represent a significant percentage of BPA's total costs. The recovery of CGS capital costs is more than 18% of BPA's total costs. While these costs represent a significant cost category, BPA's customers recognize that the reliable and safe operation of CGS is essential to BPA's power portfolio. The customers intend, however, to become more active in the EN budget process prior to the time these costs show up in BPA's rates.

At the PFR II Manager's Meeting on March 8, 2006, CGS described a need for additional funding of $13.8 Million/year for increased O&M and an increase in capital expenditures of $22.9 Million/year on average over FY07-09. These amounts would be in addition to the CGS expenditures included in BPA's Initial Rate Proposal. In the month following this meeting, CGS was able to determine that it could internally fund these additional expenditures through additional revenues from CGS uranium remarketing efforts. The result is no net increase in CGS expenditures over BPA's Initial Rate Proposal, and the effect on BPA's proposed rates is now forecasted to be a net decrease of $2 Million/year due to forecasted increased revenues from uranium remarketing.

We commend CGS for finding innovative ways to offset the costs of these additional O&M and capital requirements. We also appreciate EN staff's participation in the PFR process and expect that this will lead to better coordination of EN's funding needs and BPA's rates in the future.

We do, however, question the timing of the funding for the main condenser replacement, given that the planning and design has not yet been fully developed and other alternatives have not yet been explored. Given that there is $35 million in placeholder capital costs for the condenser replacement in the spending estimates for the FY07-09 period, we are interested in the follow-up report on this investment.

During the CGS presentation on March 8, Scott Oxenford, VP Technical Services, Energy Northwest, acknowledged that the additional O&M and capital expenditures will improve CGS performance and are expected to increase capacity factor and plant availability of CGS. According to BPA, its "forecast of 1,000 aMW for CGS in non-maintenance months provides an accurate, though slightly conservative estimate of the annual generation potential for CGS." This forecast was prepared in July 2005 and did not incorporate the effect of these additional O&M and capital expenditures. As a result, in its Final Proposal, BPA should modestly increase the BPA forecast for CGS generation output for FY07-09 to a slightly less conservative amount of 1,030 aMW in the non-maintenance months.

C. Implement the hydro-benchmarking study and associated savings.

We continue to feel that better communication is needed among BPA, BPA's customers, and the Corps and Bureau. For example, in PFR I we discovered $1.5 to $1.6 billion of Columbia River Fish Mitigation Studies that were coming into plant-in-service that had not been anticipated by the customers. During the course of PFR II we found that the Corps was considering a $30 million Flood Control Review Feasibility Study. We seriously question the advisability of this study and object to the use of ratepayer monies as a source of funding for this study of non-power uses of the FCRPS. (PPC and many others have written separate letters to the Corps on this subject.)

As a result of our review of the Northwest Regional Benchmarking Study, we find that there are significant areas for saving money in the following areas and look forward to the potential for savings from implementation of these initiatives:

- Automation of facilities
- Review of the system-wide water management function
- Sharing of maintenance practices

The customers look forward to meeting more frequently with the Corps and Bureau as we address the above topics.

D. Shift Fish & Wildlife funds from R, M & E to direct-benefit projects.

Customers believe that the $143 million Direct Program funding level as established in the 2005 PFR is fully adequate for BPA to meet its obligations under the Power Act and the Endangered Species Act (ESA). Customers continue to support BPA's initiative to increase the allocation of the Direct Program to 'on-the-ground' projects, like habitat protection and enhancement, tributary passage improvements, and hatchery improvements. This re-allocation serves two worthwhile purposes. First, by moving funds from research, monitoring, and evaluation (R, M &E) to on-the-ground projects, more money is made available to support programs that directly benefit fish. Second, such a re-allocation initiates a timely re-focusing of the region's R, M, & E efforts by reducing redundancies and building efficiencies into those programs.

We have also requested that BPA pursue cost-sharing of R, M, & E in order to better focus ratepayer funds on programs of direct benefit to fish and wildlife. We appreciate the direction that BPA has been taken in both of these areas and—regardless of BPA's financial situation—will continue to advocate for a program based on science and focused on cost-effective efforts to enhance fish and wildlife.

Finally, customers remain concerned about the Corps of Engineers' Columbia River Fish Mitigation funding assumptions. Customers are still unclear about what underlies the Corps' estimate of $1.6 billion to be spent in this program by the time it is completed. A fully formed rationale for these expenditures is necessary before such a large amount of funding is committed.

E. Do not exceed $40 million in DSI benefits.

PPC appreciates BPA's postponement of its decision, until after the conclusion of PFRII, about whether to sign the DSI contracts. Deferring that decision to this point has given BPA and its customers more time and information for assessing whether providing DSI benefits, or at what level, is appropriate.

In its Draft PFR II closeout letter, BPA determined that it would continue to propose the level of DSI benefits at $59 million per year. PPC does not support this level of benefits being provided to the DSIs through contracts for the 2007-11 period. PPC's position on the level of DSI benefits has not changed since PPC's comments on BPA's "straw proposal" for DSI service in March 2005. At that time, BPA had proposed a level of benefits to the DSIs not to exceed $40 million per year. PPC stated that if BPA was resolved to provide benefits, then those benefits should in no case exceed the proposed level of $40 million per year.

Since that time, BPA determined in its June 30, 2005, Record of Decision on Service to the Direct Service Industries for the Years FY07-11 (DSI ROD) that it would offer the DSIs $59 million per year. PPC notes that this amount is roughly a 50 percent increase over the level BPA presented in its straw proposal, and is thus a significant increase above the level at which PPC has stated the levels should be capped.

BPA's decision to offer the DSIs $59 million per year is not justified. As explained below, BPA appears to have changed its stated criteria for determining the appropriate level of DSI benefits since the June 30, 2005, DSI ROD. In that document, BPA assured customers that it would reconsider whether $59 million per year was an appropriate level of benefits for the DSIs during the FY07-11 period, in light of a likely increase in the operational costs of the FCRPS flowing from litigation over the 2004 Biological Opinion.[1] The DSI ROD clearly set out the standard by which BPA would undertake such a review. It explained:

> On June 10, 2005, the United States District Court for the District of Oregon issued an injunction that, if sustained on appeal, will likely greatly reduce the amount of water available this summer for hydroelectricity production. . . . *If this injunction is sustained on appeal, and especially if summer spill along the lines ordered in the injunction is made a regular*

[1] *See, e.g.,* DSI ROD at p. 26 ("BPA will review its decision . . . after the cost impact of the June 10, 2005, injunction becomes more clear . . . . A decision to reduce the amount of service benefits . . . up to and including a decision not to serve any aluminum smelter load, is possible.").

> *part of river operations, the rate impacts would be of extreme concern, and BPA may seek offsetting cost reductions*.[2]

BPA acknowledged, therefore, that its proposed level of benefits may indeed *not be appropriate* if 1) the June 10, 2005, injunction was sustained on appeal, and 2) summer spill along the lines ordered in the June 10, 2005, injunction were made a regular part of river operations. Subsequent to the DSI ROD, both of these conditions were realized—the Ninth Circuit Court of Appeals affirmed the District Court's spill injunction, *and* the District Court, on December 29, 2005, ordered river operations that are very similar in cost to what the June 10, 2005, injunction cost. PPC is unaware of any information indicating a likely return to a more flexible operating system.

However, in its draft closeout report, BPA offers no meaningful explanation of how the level of DSI benefits was considered in light of these stated criteria. Instead, BPA states:

> The additional review time has provided an opportunity to consider the DSI benefit levels in *light of more recent information on expected hydro system operations and a more refined understanding of net secondary revenues BPA will achieve during FY06*. In light of discussions in the PFR II and the updated information on expected hydro operations and revenues, BPA proposes to retain the maximum DSI benefit level at $59 million per year.[3]

This explanation is unpersuasive, and seems to indicate a willingness to take secondary revenues that should be available to reduce rates for preference customers and instead use those revenues to provide a subsidy to the DSIs. It also demonstrates that BPA's determination of the level of DSI benefits relied on a different standard than set forth in the June DSI ROD. In sum, BPA seeks to justify retaining the $59 million annual benefit level based on a better-than-expected net secondary revenues forecast for FY06.

This rationale both differs from the criteria stated in the DSI ROD and is a flawed standard for determining the appropriate level of DSI benefits for a 5-year period. BPA well knows that secondary revenues can vary dramatically from year to year. One year (FY06) of good net secondary revenues is not a sound basis for asserting that $59 million per year is a sustainable and reasonable level of benefits.

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[2] DSI ROD at p. 12 (emphasis added); The DSI ROD also stated that BPA will review this decision prior to contracts being signed pursuant to this ROD based on more current information about the implications of the District Court's decision *and its impact on future hydro system operations*." *Id*. (emphasis added).
[3] Draft Closeout Report at p. 9.

In the draft closeout report, BPA states that "the updated information on expected hydro operations" is a factor that partly supports its decision. Since the "expected hydro system operations" are exactly those feared at the time of the DSI ROD, they do not justify retaining the benefits.

PPC stands by its position that if BPA is intent on providing the DSIs benefits, they should be no more than $40 million per year. If that benefit is not large enough to be of value to the smelters, then BPA must abide by what it recognized in the DSI ROD—that "it is not . . . within BPA's ability, to guarantee any particular level of DSI operations, even minimal levels" since "[w]orld aluminum prices, raw materials costs, and the financial health of the companies are beyond BPA's control and play at least as large a role in the feasibility of smelter operations as power prices."

F. Accelerate implementation of EPIP Phase One and reduce Internal Operations costs by an additional $4 million/year.

PPC commends BPA for its extensive efforts to date in the Enterprise Process Improvement Program (EPIP).

In BPA's "Enterprise Process Improvement: Marketing & Sales Project Report" that was published in February 2006, BPA acknowledges that strategic objectives of "superior customer service" and "a customer-focused culture" direct its efforts. PPC commends BPA for focusing on these two critical strategic objectives and believes these strategic objectives apply to the entire BPA organization and not just to the Marketing & Sales areas.

During PFR II, BPA has continued to confirm its early estimate of savings from EPIP Phase One studies and its assessment that early process-improvement efforts should be limited to $8 Million/year on average for FY 2007-2009. BPA estimates that power-cost savings from EPIP in the $11 million to $12 million annual range should be achievable over time, but not by FY 2007. BPA also states that some of the EPIP process-improvement activities will take three to five years to complete.

PPC recommends that BPA move ahead as quickly as possible to implement all the process improvements and savings that have been clearly identified and documented in the EPIP Phase One reports. BPA has expended considerable effort in completing the six reports in EPIP Phase One. Timely and effective implementation over 1-2 years, rather than a 3-5 year timeframe, is critical to gaining more efficiencies in each of the six areas. PPC recommends that BPA include additional savings of $4 million/year to the early estimate of $8 million/year and that a total of $12 million/year for EPIP savings be included in

BPA's Final Proposal. We believe this recommendation is further bolstered by the fact that EPIP Phase Two and Three will also be completed in the near future and will produce additional savings for BPA's Power Business Line, beyond those associated with the $11-12 million quoted above.

G. Adjust conservation target by incorporating utility-funded projects, as appropriate.

We support the creation of a system for utilities to report the additional conservation they are achieving, and we hope that this information will be used to adjust BPA's target for conservation if it shows utilities are pursuing more than their share of the Council's regional conservation target. At this point in time we do not support any changes to the budget for BPA's conservation rate credit program. There are new requirements of the program, and these may prove very challenging to comply with. We should first see how successful this program is in practice before budget changes are incorporated.

A related concern involves how future conservation achievements (post 2006) will be treated in the post-2011 world. The Regional Dialogue Process has not officially come to a close, so it is difficult to say whether there will be disincentives to do conservation as a result of the decisions made in that process, but we encourage BPA to endeavor to avoid such disincentives.

H. Remove Fourmile Hill project from this rate period, model the facilitation budget through NORM, and initiate new facilitation funding process.

We support BPA's decision to remove from the FY09 renewables budget the costs associated with the Fourmile Hill Geothermal project. In addition, we are encouraged by the change in how BPA now proposes to treat its facilitation budget in rates FY07-09. It better reflects the uncertainty at this point regarding actual usage of the funds available to utilities for renewable facilitation. We want to start the process with BPA to determine how best to use these funds.

As with conservation achievements post-2006, we are concerned about how utility-developed renewable resources will be treated in post-2011 world. We hope that as BPA refines its Regional Dialogue closeout documents, it will avoid creating disincentives to utility-developed renewable resources.

I. Include customers in the Council's budget-planning process.

The customers intend to become more active in the review of the Council's budget before it enters the realm of BPA cost recovery. During the public Council budget-review period, we will request that the Council present to the customers its proposed budgets at the ongoing BPA financial-review meetings that are held at PPC.

J. Initiate on-going examination of forecasted budgets, with appropriate customer participation.

In both the current PFR process and its predecessor, we have found that some areas we might think would be ripe for additional cost efficiencies are actually less flexible as the rate period nears. From this we conclude that a cost review for the next rate period (FY10-11) should get underway sooner than mid FY08. However, because *other* areas *are* ripe for change with short notice prior to the start of a rate period, we encourage an additional examination of the FY10-11 costs in FY09 during the rate case (similar to the PFR II process). Similarly, we would like to see the promised capital program process begin this summer and offer customers with sufficient opportunity for debate, discussion, and comment before capital commitments are made.

In addition, in the next few years BPA will be negotiating and signing new, long-term power contracts with preference customers that will commence service in the post-2011 period. BPA and preference customers will be able to make more informed decisions if the budget process for the post-2011 period is started at the earliest possible date. Doing so will allow customers to understand the spending trade-offs and participate in the decisions regarding BPA's spending commitments, which will drive the level of BPA's rates in the post-2011 period.

In conclusion, thank you for conducting a constructive PFR II process, and for considering these recommendations and comments for achieving even more fruitful results. If you have any questions, please feel free to contact me or Annick Chalier, achalier@ppcpdx.org.

Sincerely,

Marilyn Showalter
Executive Director