Bonneville Power Administration

Power Business Line's
Power Function Review II Final Closeout Report
June 1, 2006

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Final Closeout Report

Overview

The last six years have presented the Pacific Northwest with major challenges in trying to recover from the West Coast energy crisis while also experiencing a series of below average water years as well as an economic recession. The good news is that if this year remains on course as forecast in the FY 2006 2nd Quarter Review, the Bonneville Power Administration (BPA) will have made up a majority of its previous losses as it enters the FY 2007-2009 power rate period.

As the region experienced increasingly higher electricity prices BPA's challenge has been to keep its costs and rates as low as possible to help the regional economy while still meeting its mission objectives. BPA welcomed the region's input on how to most effectively meet this challenge. When BPA found itself facing financial difficulties in 2003, it reached out to the region for help in making tough financial decisions. BPA began a series of regional processes reviewing the Power business costs, starting with Financial Choices and General Managers' meetings in 2003. These were followed by the Sounding Board in 2004, Power Function Review in 2005 and Power Function Review II in 2006.

BPA believes it is important to inform and educate, as well as listen to regional interests about the costs BPA faces to its mission, while supplying federal power to its regional customers at the lowest possible rates, consistent with sound business principles. One challenge lies in evaluating the tradeoffs among all these areas and determining what is a reasonable balance. Another is to ensure that each function is being conducted as efficiently as possible. The region's input and support is important on both these challenges.

Power Function Review

BPA kicked off the original Power Function Review (PFR I) in early 2005 to seek input from the region on its cost structure for the FY 2007-2009 power rate period. BPA heard from many customer groups, constituents and tribes about how important it is for them to have the opportunity to understand and have substantive input on what costs BPA rates will cover and to provide input into program funding levels prior to the rate setting process since cost levels are not part of the formal rate-setting process. BPA committed to hold PFR public meetings prior to both the initial power rate proposal and the final proposal. The PFR I process was designed to encourage and allow full public review and comment by anyone who wanted the chance to understand, ask questions and provide feedback on program funding levels that are recovered by power rates.

The PFR I examined all the program levels and identified $96 million a year in cost savings over previously proposed levels. At the time of the PFR I closeout report, there were still some unresolved issues; therefore, BPA decided it would hold a series of follow-up public meetings to address those issues as well as any other issues raised by interested persons prior to setting BPA's final power rates.

Power Function Review II

This second series of meetings became known as the Power Function Review II (PFR II). This review looked at all the outstanding issues from the PFR I as well as a number of new issues raised by interested persons. In all, the Power PFR II found an additional $26 million a year in net savings over and above the savings identified in the PFR I. Together, the PFR I and PFR II captured a total estimated rate period savings of $122 million per year.

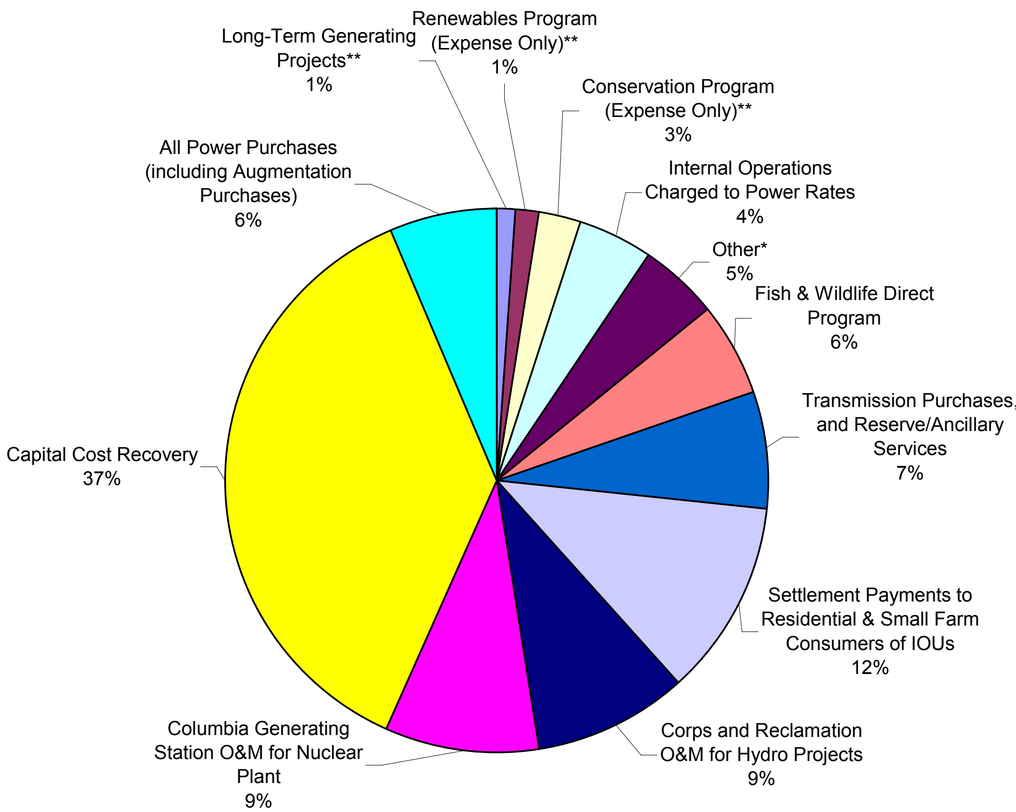
PFR II examined the following areas.

- Changes in capital cost recovery
  - Amortization periods for conservation and Fish and Wildlife investments
  - Columbia Generating Station debt life and additional capital needs
  - Columbia River Fish Mitigation plant-in-service schedule
  - Updating 2005 actuals in rate case repayment study
- Columbia Generating Station operations and maintenance
- Corps of Engineers and Bureau of Reclamation operations and maintenance
- Transmission cost associated with secondary sales
- Fish and wildlife monitoring and evaluation costs
- Benefit level to the Direct Service Industry (DSI)
- Level of internal operations charged to power
- Conservation by utilities through self funding and cost of additional conservation
- Forecast in the Renewables program of the Calpine Geothermal online date and the amount for facilitation funds

The level of costs going into the final power revenue requirement is not only important in setting rates but it also reflects BPA's commitment to manage to those levels throughout the rate period. Because the proposed power rate has adjustment mechanisms that are set every year of the rate period and can adjust the actual power rate customers pay, committing to manage to the cost levels set in the rate period is important. The PFR II does not signal the end of a process to manage costs, but rather continues an ongoing dialogue with the region on cost management. BPA is committed to keeping the lines of communication open throughout the rate period by meeting monthly with groups such as the Public Power Council and Customer Collaborative as well as other groups as requested. BPA is also kicking off its Capital Planning Review Process in June 2006. This process will take an agency-wide look at how capital funds are spent and seek feedback from interested persons.

BPA released a draft PFR II report in April 2006 seeking public review and comment on preliminary conclusions for program levels. BPA received various comments and this final report addresses those comments and outlines BPA's conclusions. Results from this report will be used in the 2007 final power rate proposal.

Average Annual Power Costs for FY 2007-2009



**Other includes: US Fish & Wildlife Lower Snake Hatcheries, Planning Council, Colville Settlement, Spokane Settlement, Trojan Decommissioning, WNP 1&3 Decommissioning, PNCA Headwater Benefit, Hedging/Mitigation, Other Environmental Requirements, Civil Service Retirement System, Other Income, Expense, Adjustments (DSI benefits for FY07-09)*
***This category has offsetting aMWs .*

The Rate Setting Process

Power Function Review Process ← $\dfrac{\text{Costs} - \text{Credits} + \text{Risk}}{\text{Loads}} = \text{Rate}$ → Rate Case Process

The PFR I and II were designed to increase understanding and seek feedback on the biggest driver of power rates: cost levels. However, much public comment expressed frustration of just talking about one piece of the equation and not seeing the other pieces, such as credits, risk and load issues at the same time. To address this frustration, BPA provided rate impact estimates based on the initial proposal estimates and accounting for certain other factors that were changing at the same time as the costs. PFR II was designed to conclude in time for results to be reflected in the rate case revenue requirement. This timing allows all the drivers of costs to be examined in time to incorporate changes in revenue requirements while allowing the formal rate setting process to proceed on schedule. The PFR processes allowed a wide spectrum of individuals and organizations the opportunity to review and comment on cost levels that go into rates.

Following are the changes BPA will make to the costs used in its initial proposal for FY 2007-2009 rates in each of the major cost categories for use in setting power rates, based on the public comment and updated information and analysis in PFR II.

PFR II Final Report FY 2007-2009 Cost Changes

Estimated capital cost recovery

The largest area of power cost is capital cost recovery. However, unlike other program areas, this cost is not a single, discrete program but rather primarily the result of capital investments BPA and other resource agencies (Corps of Engineers (Corps), Bureau of Reclamation (Reclamation), and Energy Northwest (EN)) have made over time. In addition, forecasts of future investments and BPA's debt management practices have some bearing on the cost level. In 2005, PFR I examined each of the major areas in this category and the drivers behind those costs.

The outstanding issue held over from the PFR I process was whether to extend Columbia Generating Station (CGS) debt, both new and existing. Other interest areas included amortization periods for conservation as well as for BPA's fish and wildlife program capital investments, capitalizing land and water acquisitions for fish, Columbia River Fish Mitigation plant-in-service assumptions, and updating for actual FY 2005 financial results. Each of these areas was reexamined in PFR II. Decreases and increases to be included in BPA's final repayment study in the power rate case are described below and listed in the score card at the end. The final calculation of the effect of these changes will occur when all of these adjustments are incorporated in the final repayment study.

During the PFR and other forums, BPA provided background information on its internal federal and nonfederal debt management policies and practices. While these policies and practices are not decided in the PFR, BPA understands the importance of sharing this type of information so interested persons have an opportunity to understand the implications of debt management decisions and capital investment forecasts on the revenue requirement. Throughout this process customers made several suggestions on potential debt management actions, such as EN debt extension, which BPA followed up on and agreed with customers and will be incorporated in BPA's debt management analysis.

CGS debt extension: In the PFR I, participants encouraged BPA and EN to study the feasibility of extending some of the current CGS debt and debt financing of CGS capital projects to FY 2024, which is the year through which the plant is currently licensed. BPA, its customers, and EN collaborated to evaluate this concept prior to the PFR II process. The EN executive board approved both actions, and BPA and EN priced bonds in March 2006, securing the total estimated $17 million ($16 M for existing debt and $1 million for new debt) annual cost savings shown below in the score card. This will be reflected in the final power rate proposal. This is the largest single cost reduction identified through PFR II.

Conservation amortization period: Following PFR I discussions, BPA changed the amortization period for conservation investment in the initial power rate proposal from a declining 10-year period to a five-year period. This change resulted due to a shift in the nature of investments from one of power augmentation for the FY 2002-2006 period to conservation acquisition for FY 2007-2009. In PFR II BPA was asked to analyze and consider changing the conservation amortization period from five years to 15 years.

Analysis indicates that this change would have almost no impact on the revenue requirement in FY 2007-2009, but there would be a significant decrease in the FY 2012-2015 period. After FY 2015, the reduction would shrink markedly. The five-year amortization puts less pressure on BPA's limited borrowing authority, reduces the risk of stranded investments, and appears to be more consistent with industry practice. Even though customer feedback encouraged BPA to extend the amortization life to 15 years despite the lack of rate benefit over the next five years, BPA believes the factors listed above outweigh the benefits of extending the amortization life at this time. For these reasons, and because the longer amortization period would have virtually no rate impact in FY 2007-2009, the draft rate case record of decision will indicate that BPA will not change the five-year amortization period for conservation acquisition investments.

Fish and wildlife amortization period: Based on a request in the PFR II by participants who wanted more funding available for fish habitat acquisitions, BPA analyzed and considered amortizing BPA's fish and wildlife program capital investments over a longer period than the current 15-year period. BPA evaluated the impact of a customer-suggested 25-year amortization period as part of the PFR II process and found that such a change would have virtually no impact on rates in the upcoming rate period.

Despite this lack of rate benefit, public comment encouraged BPA to extend the amortization for fish and wildlife investment to greater than the current 15 years. Before such a change in accounting policy can occur, there must be a notable accounting event that would cause BPA to reevaluate its fish and wildlife capitalization policies. No such events have occurred. The nature of the program's investments has not changed since the creation of the existing policy in 1984. Because of this, and because of the lack of rate benefit, BPA does not plan to change the amortization period for these investments for the final rate studies.

Capitalization of land and water acquisitions for fish: In a PFR II workshop, participants who proposed increases in spending on fish and wildlife measures also requested that BPA consider capitalizing land and water acquisitions for fish. Debt-financing such acquisitions would decrease the impact on proposed rates. BPA has explored this proposal and is not inclined to change its existing treatment of this type of acquisition. These kinds of acquisitions do not meet criteria for capitalization under Statement of Financial Accounting Standards (FAS) 71, Accounting for Certain Types of Regulation. Specifically, accounting standards require that for FAS 71 assets (non-revenue-producing assets) to be capitalized there must be a measurable future benefit. Since the measurable future benefit for land acquisitions for wildlife is the commonly-accepted metric of "habitat units", and these acquisitions are credited towards meeting a defined measurable obligation, land acquisitions can be capitalized. However, because there is no established quantified or measurable obligation for acquisition of land for fish mitigation or acquisition of water rights, nor is there a metric for crediting such acquisitions towards a defined obligation, these types of projects generally cannot meet the capitalization criteria. Hence, BPA does not plan to revise the existing accounting treatment for this type of acquisition. However, if such a crediting metric is developed, BPA will reconsider whether land and water rights acquisitions for anadromous fish mitigation purposes could be capitalized within our existing capitalization policy.

Updating capital cost recovery estimates to reflect 2005 actual financial results: PFR II comments encouraged BPA to update its capital investments and payments to reflect 2005 actual results. The final power rate proposal will reflect all actual FY 2005 transactions. As shown in the score card below, the current estimate is that this update will bring annual costs down by about $3.5 million.

Columbia River Fish Mitigation Program: Customers asked for an update on the Corps' Columbia River Fish Mitigation (CRFM) project plant-in-service schedule. BPA has stated it intends to reflect in the final power rate proposal any decision made by the Corps regarding its schedule for placing investment into service based on new guidance to the Corps from the Department of Defense Inspector General (DOD IG). The issue in question is the significant amount of appropriated capital spending, predominately associated with studies, being held as construction work-in- progress (CWIP). The original Congressional report language authorizing CRFM in 1991 suggested that study costs should be retained in CWIP until the entire project was completed. When appropriations were first made, Congress expected the Corps to finish in 2001. Based on this interpretation, the Corps has accumulated several hundred million dollars worth of studies in CWIP. Many are associated with capital investments that are already in place or planned for the future at specific dams. Others are associated with studies that were completed or with system-wide measures that are not directly assignable to specific dams. The Corps began reviewing this practice in 2005. The DOD IG had reviewed the CRFM project and recommended that the backlog of studies be transferred into plant-in-service and that future studies be transferred into service upon completion. At the time of the PFR close-out report, the review of this issue was being considered by the Corps. In the initial power rate proposal BPA selected a plant-in-service forecast from the alternatives available at that time but acknowledged that the forecast could change.

At the February 16, 2006 PFR II workshop, BPA shared the Corps' most recent estimate. The major change at that time was that significantly more investment was to be placed into service in FY 2006 than was forecast in the initial power rate proposal, $284 million versus $22 million. This estimate was presented as preliminary and was estimated to result in roughly a $5 million increase in interest expense per year. Since that workshop, the Corps' forecast has been updated for use in the rate case. The most significant change is the plant-in-service estimate for FY 2006 which is significantly higher, up to $394 million from $22 million in the initial power rate proposal. The impact of this revised forecast is estimated to result in roughly an increase of $9 million in interest expense compared to the initial proposal forecast. Regional Corps officials understand the rate implications of this change; however, the Corps Headquarters has concurred with the DOD IG recommendation that placing the backlog of studies into service is the appropriate accounting treatment for these costs.

BPA also heard comments about the Corps currently proposed flood control study. Most comments encouraged canceling the study since it appears to be a non-power cost that should not be borne by electric ratepayers. Even though this cost category is largely borne by ratepayers, BPA is not the decision maker on this topic. This decision will be made by the Corps; however, it welcomed regional input on this issue. The Corps is currently considering what to do in light of receiving numerous (23) letters commenting on its proposed comprehensive flood control study. The main concerns expressed in the letters were disagreement with the proposed scope of the study and disagreement with the proposed funding source, which was CRFM. The Corps has indicated that it is still working the issue internally and will report back to the region sometime in late June. No costs for this study will be included in BPA's final power rate proposal.

Increase in borrowing for CGS capital needs: Since PFR I, several issues have developed related to equipment reliability and performance at CGS. EN has embarked on a plan that increases CGS maintenance and equipment replacements in order to improve equipment reliability and plant performance. The plan will focus on items such as pump and motor failures, turbine controls, dose reduction, and condenser leaks. As a result, there are increases in the CGS forecast for funding needs over what was presented in the PFR I (EN's 2005 long-range forecast). A significant portion of the cost increase (an average of about $43 million per year) is related to capital projects and will be debt financed. This leads to an annual average increase in debt service payments of approximately $2.5 million (this figure will be revised for the final power rate proposal when the Repayment Model Study is updated). The forecast by EN for the FY 2007-2009 rate period includes place-holder funding of $35 million to replace the main condenser at CGS. EN acknowledged that the plan, design, and cost estimate for the condenser replacement has not yet been fully developed, and that a study to address and develop a plan for dealing with the condenser leaks must be completed. Because the condenser replacement would be capitalized, including it adds only $1 million to 2007-2009 average annual costs. Some customers supported condenser replacement based on existing information, while others supported condenser replacement if replacement is deemed necessary after consideration of the alternatives. BPA recognizes that there are issues and problems with the condenser which must be addressed, and will continue to work with EN to explore repair/replacement alternatives, up to and including condenser replacement if that is determined to be the most cost effective alternative. Pending this conclusion, BPA will include the condenser replacement costs for FY 2009 in the risk analysis for purposes of the final rate studies.

BPA customers expressed interest in receiving a follow-up report on EN's plan in regard to the condenser issue, and EN and BPA intend to provide this follow up. In addition, with the significant investment in CGS being made to improve performance and reliability, customers asked that consideration be given to developing improvement targets and performance indicators to track the results of the reliability investments. BPA will work with EN to determine if reasonable performance measures can be developed and adopted.

Interest Credit: The interest credit that is factored into the net federal interest calculation will likely be higher than anticipated in the initial proposal. BPA reserves will probably be higher at the beginning of the rate period because 2006 net revenues are now expected to be substantially higher than assumed for the initial power rate proposal. The interest credit could be roughly $10 million higher per year than in the initial proposal. The size of the credit will be determined in the final studies.

Columbia Generating Station O&M

In the PFR I, CGS was facing many issues including rising security costs, rapidly increasing fuel prices, aging and obsolete equipment, on-site spent fuel storage and rising employee benefit costs. In response, EN went through a benchmarking effort to identify areas for efficiency improvements. As a result, EN committed to bring down its forecast of O&M costs in the FY 2007-2009 rate period by $22 million per year on average. Since then, as noted above, EN has reviewed and refined its forecast for the FY 2007-2009 rate period and identified the need for an additional $14 million per year on average in O&M funding for plant maintenance and equipment reliability improvements. However, these increases are offset by active management of nuclear fuel procurement and planning that has resulted in savings over projected costs in the PFR I of $16 million per year on average. This results in a net decrease of $2 million per year in the CGS O&M forecast. This decrease, coupled with the increase in capital financing costs mentioned above, results in costs for CGS very close to those assumed in BPA's WP-07 initial power rate proposal.

BPA also received comments encouraging an increase in the CGS output forecast. The output forecast from CGS is a rate case issue and is not decided in the PFR II. BPA has expressed the view in rate case testimony that increasing the CGS output forecast would not be appropriate because the additional work EN needs to accomplish at CGS may put pressure on its output in the coming rate period. This issue will ultimately be decided in the rate case.

Concern was expressed in public comments about the possibility that debt refinancing could impact the future funding of fish and wildlife activities. When BPA pursued debt extension of CGS bonds, it was in the context of matching the life of the plant to the life of the bonds. This action should not have any impact on the funding and schedule of needed fish and wildlife investments. BPA is committed to fund its fish and wildlife obligations regardless of CGS debt payments.

Corps & Reclamation O&M

In the PFR I process, the Corps and Reclamation developed spending levels that reflected minimum cost requirements while still meeting power generation and reliability requirements for the region. One of the checks and balances the Corps and Reclamation use in running hydro facilities is the result of national benchmarking efforts of like-hydro facilities. The Northwest federal hydro projects score well, coming in under the average overall in operations and maintenance costs as do other regional hydro facilities. In the PFR I, it was suggested that the federal agencies benchmark themselves with regional nonfederal hydro facilities in order to identify additional efficiency opportunities.

BPA committed to follow up and initiated a regional hydro benchmarking effort last fall that included the Corps, Reclamation, Grant County PUD, Chelan County PUD, Seattle City Light, and Tacoma Power, and reviewed 23 federal and nonfederal hydro projects. The study is publicly available at *http://www.bpa.gov/power/pl/review/nw_hydro_benchmark_study_03-2006.pdf*. The study finds that, for the majority of functions benchmarked, costs for federal projects and other Northwest facilities were similar. However, the report also points out opportunity areas for potential efficiencies in the longer term for the O&M program. These include potential automation of more federal projects, review of the water management function at the three federal agencies for process and cost efficiencies, and sharing of maintenance practices among the various projects to identify opportunities for improvement. Customers urged the federal agencies to pursue these potential savings opportunities aggressively.

BPA will work actively with the Corps and Reclamation to assess these opportunities and to capture any savings available through them as rapidly as possible. BPA believes, however, that it is premature to include cost savings in the final power rate proposal for the upcoming rate period. This approach is consistent with BPA's commitment and practice to include costs in rates that it can and will manage to. Under the proposed rate adjustment mechanisms proposed for the next rate period, customers will very likely see the rate benefit of any savings actually achieved within the 2007-2009 rate period.

Another theme that came through in the comments is a perception that the Corps and Reclamation response to customer concerns was bureaucratic and less than helpful in the area of cost control. Both agencies, along with BPA, are assuring the region they want to work with the region to deliver the best product at the lowest cost and are open to regional feedback. All three agencies have committed to meet regularly with interested parties, such as the Public Power Council technical and executive committees, to brief them on hydro program activities and performance as well as any changes that are appearing in the future.

Finally, even though the benchmarking process is complete, collaborative efforts among other regional generating facilities are not over. BPA, the Corps and Reclamation have committed to a series of follow-up meetings with Pacific Northwest regional generating utilities to pursue best practices in operations and maintenance. This kind of information exchange will benefit both the federal and regional utilities, and ultimately will improve practices and system reliability in the region.

Transmission expense

At the beginning of the PFR II process, BPA was asked to examine how it accounts for its transmission expenses related to secondary energy sales. Some thought there might be double-counting involved in recording actual transactions, and that it was a potential area for reduction if that were true. Interested persons met with BPA subject matter experts to thoroughly examine this concern. At the conclusion of this review, parties determined that the transmission expense is accounted for correctly in accounting records and through the rate setting process.

Fish & wildlife O&M

In the PFR I, BPA emphasized its commitment to fulfill its fish and wildlife obligations through managing to clearly defined performance objectives and implementing the most cost effective strategies for meeting these objectives. As part of this commitment, BPA's fish and wildlife program managers identified the need for a more strategic and focused research, monitoring and evaluation program and shifted funding from Research, Monitoring & Evaluation (RM&E) activities to more "on the ground" work directly benefiting fish and wildlife, such as habitat protection and enhancement strategies as identified in the Northwest Power and Conservation Council's (Council) newly adopted subbasin plans, BPA was asked to follow-up on how BPA is planning to deliver its fish and wildlife RM&E commitments.

BPA is working with regional fish and wildlife managers and others through the joint BPA-Council FY 2007-2009 Proposal Solicitation Process to further refine and develop a draft framework for integrating RM&E efforts into the fish and wildlife program. Regional federal, tribal and state resource management agencies are completing and summarizing a survey of key management questions, needs and monitoring inventory. The Council has recently adopted its Regional Fish and Wildlife Research Plan, and BPA and the regional federal agencies are updating their RM&E Plan in 2006. The NOAA Fisheries Recovery Planning Framework developed to date also includes an RM&E framework consistent with these other regional efforts. By further refocusing BPA-funded RM&E efforts in the basin, including identification of appropriate cost sharing and partnering with others, current RM&E funding can be shifted to implement increased on-the-ground efforts which have been identified as priority strategies in the recently completed Council subbasin plans and NOAA Fisheries draft recovery plans.

BPA received a wide range of feedback during the comment period for this program. Some comments supported the shift in funds from RM&E to on-the-ground work as well as the overall funding level, while others thought the funding levels in general were too low. There was also concern about the importance of designing rates to adequately fund fish and wildlife activities while ensuring repayment to the U.S. Treasury.

As concluded in the PFR I, BPA believes its total $179 million per year fish and wildlife program funding level ($143 million expense and $36 million capital) allows for implementation of its Northwest Power Act and Endangered Species Act (ESA) offsite mitigation responsibilities. These may include high priority habitat strategies as identified in the subbasin plans such as riparian habitat protection for anadromous and resident fish, tributary passage improvements, hatchery improvements, and the continuation of effective measures that mitigate for wildlife losses due to construction of and inundation of land by the Federal Columbia River Power System (FCRPS). Any savings in the RM&E arena will be redirected to projects yielding direct benefits to fish and wildlife affected by the federal hydropower system.

We are considering and clarifying ESA needs for anadromous fish through a new FCRPS biological opinion and the collaborative remand process that Judge Redden oversees. These needs, as they are identified, will be closely coordinated with the ongoing Council Proposal Solicitation and Review Process that will provide recommendations of fish and wildlife mitigation projects to BPA in October 2006, for potential implementation in FY 2007-2009. The Redden collaborative process is anticipated to produce a new FCRPS biological opinion by spring 2007.

Some PFR II comments urged that fish and wildlife costs used in setting power rates be significantly increased to reflect spending increases they believed necessary to implement subbasin plans and other planning processes (for example, the Redden Collaborative Process, NOAA Fisheries recovery planning, regional hatchery review, and the Council's Provincial Review Process). BPA believes that controlling program infrastructure costs—such as coordination, monitoring and evaluation costs—will create the opportunity to commit more spending to habitat and hatchery efforts and provide more room for on-the-ground benefits to fish and wildlife, as identified in the subbasin plans and draft recovery plans To the extent ESA needs for anadromous fish or other mitigation costs exceed BPA's currently planned budgets, BPA can address those needs through, among other things, prioritization of its fish and wildlife project portfolio, seeking additional cost-sharing where entities beside BPA have overlapping authority to provide similar types of mitigation, and using the same financial tools it has available to deal with other BPA program costs that increase beyond planned budget levels in the FY 2007-2009 rate period.

DSI benefits

The June 30, 2005 record of decision on direct-service industry (DSI ROD) benefits noted that BPA would revisit the decision to offer service to the DSIs once the financial impact of changes in the hydroelectric system operations stemming from court rulings were better known. The ROD proposed capping the benefits at $59 million per year with the possibility that actual amounts could be lower depending on actual DSI operation levels and the difference between market prices and BPA's priority-firm (PF) rate. (Because it is not certain that the DSIs will actually be able claim all these payments, the expected value of payments in the initial rate analysis was $53 million.) Based on comments from a follow-on public process reviewing draft smelter prototype contracts, BPA decided to examine the level of DSI benefits in the PFR II.

During the PFR II discussions, questions were raised about PF rate adjustments and the effect on DSI benefit levels. If benefits are provided as a direct power sale at a PF equivalent rate, changes in the rate would directly impact the price a DSI pays. When the power sale is monetized, as will occur for at least FY 2007-2009, the impact is more indirect. However, the formula that determines the DSI benefit levels is subject to all rate adjustments of BPA's PF rate. The draft contract sets a cap on DSI benefits of between $12 and $24 per megawatt-hour, depending on the smelter's operating level. To the extent that the difference between market and PF is less than these levels, the smelters would continue to be directly affected by changes to PF. During the PFR II discussions it was suggested that BPA consider a more direct application of changes in the PF rate, applying adjustments directly to the benefit level rather than indirectly through the PF rate. BPA's draft smelter prototype contract limits DSI benefits such that their effective power costs can't be lower than PF. The direct approach would also mean that, in times of high power prices, their business risk would increase further since they could not count on the BPA benefit. Changes in PF already have a significant effect on the DSIs. For these reasons BPA believes that the indirect approach best meets our dual goals of broadly applying rate adjustments and providing limited benefits to support DSI operations.

The additional review time has provided an opportunity to consider the DSI benefit levels in the context of more recent information on expected hydro system operations and a more refined understanding of net secondary revenues BPA is forecast to achieve during FY 2006. In light of discussions in the PFR II and the updated information on expected hydro operations and revenues, BPA will retain the maximum DSI benefit level at $59 million per year. BPA originally chose the $59 million level to balance benefits to smelters and their jobs with a minimal rate impact on other customers. Had the actual FY 2005 results been worse than expected or had FY 2006 hydro operations or water conditions made expected net secondary revenues substantially lower, BPA may have needed to adjust the balance. But BPA believes recent information shows financial results are on track to be at least as good as had been expected when the DSI service decision was originally made.

Several comments on the PFR II Draft Closeout Report questioned BPA's proposal to retain the $59 million benefit level and noted that the BPA's current positive financial results are not necessarily a predictor of the conditions and secondary revenues BPA would experience in future years. BPA acknowledges this fact. However, the fact that BPA's revenues vary with market and water conditions has always been an important part of the context for DSI benefit decisions. The purpose behind the reexamination of the $59 million amount was to decide whether the changes in BPA's hydro operations so significantly alter BPA's expected near term financial picture, that DSI benefit levels should be changed. BPA delayed the financial benefit decision to gather information about its own operations, and to better understand its starting FY 2007 financial conditions.

The comments in this process made it clear that many public utility customers, and their consumers, do not believe that the importance of support to the DSIs outweighs the negative impacts of higher PF rates. These comments highlight the importance of BPA's decision to have a known and capped cost on DSI benefit levels even though DSIs have been equally clear they would like to see higher benefit levels. While the costs of changes to hydro operations have impacted BPA's revenues, the actual operations the court ordered for 2006 were less costly than had been proposed by the plaintiffs in the litigation. BPA has concluded in this PFR II process that these costs are not enough to require a change in the balance originally proposed and will retain the benefit level at $59 million.

In the very near future, BPA will be issuing a supplement to the DSI ROD and moving to sign contracts to implement the decisions of the DSI ROD. That supplement to the ROD will address in detail the comments received on the DSI draft prototypes. Once signed, the supplement to the DSI ROD will be available on the BPA Web site at *http://www.bpa.gov/corporate/pubs/RODS/2006/*.

Trojan decommissioning

The Trojan decommissioning fund was not a topic in the PFR II because its forecast did not appear to have changed. Since the time of the workshops, BPA received an updated forecast reflecting lower costs. The Trojan decommissioning forecasts in the initial power rate proposal used PGE forecasts that were prepared for decision-making purposes as to whether to do project demolition work now, or do it later when the spent nuclear fuel is transferred to the DOE repository. The estimates were prepared using information from engineering consultants hired by PGE. PGE put the demolition work out for bid and the bids received back from the contractors were significantly under the estimated amounts. This results in a $1.2 million per year average savings from the initial power rate proposal.

BPA is not expecting any more major changes in the Trojan decommissioning estimates at this time. Trojan will finish the planned demolition work in 2008 and then will be maintaining the Independent Spent Fuel Storage Installation until DOE takes possession of the spent nuclear fuel now being stored on site. BPA will continue to pay EWEB's portion of this ongoing cost.

Internal operations charged to power

Internal operations charged to BPA's power costs may be a small number compared to the other power program areas, but it is the one that BPA can exert the most control over. Starting in 2002, BPA took on the task of greatly reducing all areas that were discretionary, such as travel, training, supplemental labor contracts, retention bonuses and awards, to name a few. Every line item that makes up the internal operations charged to power category was scrutinized and cut where possible without negatively impacting our core mission. As a result of these efforts, BPA's average internal power costs in FY 2003-2006 came in below the FY 2001 level, despite annual cost of living increases and continuing additions to BPA's responsibilities.

To ensure BPA found every savings possible, the agency embarked on the Enterprise Process Improvement Program (EPIP) in 2004. Customer representatives helped BPA scope this process to find further efficiencies in internal operations. Since that process started, BPA has been on the path to implement phase 1 of the recommended process improvements identified with the help of KEMA Consulting, which is helping BPA realize potential savings and efficiencies. In the PFR I, BPA included an $8 million per year reduction in expected internal operations costs charged to power in order to reflect savings it could achieve through these efficiency projects for the FY 2007-2009 timeframe.

BPA is currently in the midst of assessing where the EPIPs and our nearly-decided One-BPA Culture, Culture, Organization and Governance (COG) structure will leave our internal costs for FY 2007-2009. Because of this uncertainty, BPA is not able to determine with the normal level of precision and confidence what internal costs BPA can manage to in FY 2007-2009. Ultimately, the EPIP initiatives should allow savings of $12 million or more in BPA's power costs post FY 2009. Many customers called for savings at this level to be included in the PFR II closeout. We are on track to realize EPIP savings, but other factors are driving internal costs up. These include such items as increases in legal support costs driven by continuing litigation in categories as diverse as power products to biological challenges, Continuity of Operations (emergency) Planning initiatives, security initiatives and other new costs. In addition, much of the savings in each of the EPIP areas relies on process redesign, automation and reduced staffing levels through separation incentives and attrition, all of which will take several years to fully implement. In particular, staffing reductions take time and their timing is not easy to predict. These factors make it imprudent to assume that we can cut further than $8 million per year, and make achieving the $8 million target a major challenge. Although several comments encouraged BPA to assume greater cost savings then had been assumed in the PFR I process, it is not prudent to include greater savings than was assumed in the PFR I process.

Despite these challenges, BPA will retain the $8 million/year reduction (on average over the three-year rate period) for the final rate proposal and work aggressively to meet that target. While all of the projected savings will not be realized in the FY 2007-2009 rate period, BPA will seek to prudently maximize internal cost savings and those savings will be passed through in rates as they are achieved.

Conservation program

Prior to the 2007 initial power rate proposal, BPA designed a portfolio of energy efficiency programs that would achieve BPA's goal of meeting its conservation target at the least cost. BPA relied heavily on the Post-2006 Conservation Workgroup's recommendations in designing its proposed program approach. As part of the PFR II process, two additional areas were examined for their potential cost savings. The first suggested that BPA consider counting conservation done by utilities "on their own nickel" toward BPA's target. BPA has put in place a systematic way for customers to voluntarily report their self-funded conservation. At this point, it is too early in the process to count on such self-funded conservation in rates, but the program will be monitored and evaluated with customers throughout the rate period to determine how much savings occur and if there is any potential for cost savings. BPA's proposed rate adjustment mechanisms will allow any savings to be reflected in the calculation of rates. Participants supported this approach and encouraged incorporating it in rates as appropriate.

A second area of interest in the PFR II was how much it would cost ratepayers to increase the amount of conservation funding. BPA reviewed and analyzed this suggestion, which showed a very small rate increase in the short term. Even though it is a small rate impact, increasing the spending level would not be consistent with BPA's fundamental strategic objective, which is to achieve its share of the Council's cost effective conservation targets at the lowest possible cost. BPA believes that its funding levels are appropriate for accomplishing this objective. BPA does not feel it is prudent to increase its conservation funding without it being directly linked to program objectives. However, BPA will monitor its progress on achieving its share of the Council's conservation targets and make the necessary funding adjustments should there be a risk of not achieving the targets.

Renewables program

As part of the short-term Regional Dialogue process, BPA decided in February 2005 to focus on facilitating the development and acquisition of renewable resources by its customers rather than directly acquiring renewable resources. In addition, the energization date for Calpine's Fourmile Hill geothermal project, originally slated for energization in early FY 2007, was delayed to FY 2009.

Both the Calpine Fourmile Hill geothermal power purchase contract and the facilitation costs were re-examined in PFR II. Since the PFR I, the Calpine contract has gone through arbitration, which extended Calpine's time to energize the project by more than four years. Subsequently, BPA determined that the earliest the project could be energized would likely be FY 2010. Due to this delay and comments received from participants, BPA will remove the energy expenses from the project from the FY 2009 renewables program forecast. This results in a cost reduction (net of the value of the output of the project) of around $18 million in FY 2009 or an average $6 million per year over the rate period.

With respect to facilitation costs, BPA remains committed to its 2005 decision that it would spend up to a net of $21 million per year in the FY 2007-2011 period to facilitate the development of renewable resources. In addition, another $5 million ($1.6 million/year over FY 2007-2009) will carry forward from the existing FY 2002-2006 rate discount program, representing BPA's commitment to "back up" the Conservation and Renewables Discount (C&RD) program in the event that customers chose not to devote at least $30 million of their C&RD funds to renewables in that period (they actually will spend about $25 million). This brings the annual facilitation spending cap up to a net of $22 million for the FY 2007-2011 rate period.

Of this net $22 million maximum, $6 million is earmarked in the rate case for the Conservation Rate Credit (CRC) program. The remaining question is how much additional facilitation spending is likely to occur in the FY 2007 rate period. BPA does not believe it is appropriate to embed in rates the forecast that the full cap amount will be spent when there is so much uncertainty about how much will actually be spent. Some commenters agreed and encouraged the modeling of facilitation costs through a risk mechanism called NORM (Non Operating Risk Model). Therefore, BPA plans to retain the flexibility to spend up to the cap for facilitation efforts as necessary, but to assume in rates that the expected value of actual spending will be 25 percent of the cap in FY 2007 and 50 percent in FY 2008 and FY 2009. BPA will include the full range of uncertainty in spending from zero to the cap in the rate case risk analysis (NORM). This would translate to expected values reflected in rates of $4 million in FY 2007, $8 million in FY 2008 and $8 million in FY 2009. If these expected amounts later appear to be insufficient for needed facilitation efforts, BPA will then consult with interested parties on the matter and will increase spending up to the cap if necessary.

BPA will be engaging the region further in the coming months on the challenges the region faces in meeting the Council's power plan which calls for 5000 MW of new renewables over the next 20 years. These discussions will help better define the role of BPA's facilitation efforts towards achieving this goal.

Miscellaneous

There were a number of other comments that did not fit neatly into a program area. Such comments included feedback that BPA costs were too high and it should take more aggressive cost cutting measures, identify an additional $30 million per year in cost savings in order to meet the wholesale rate target of $27 per megawatt hour, and to start a serious discussion to determine whether BPA's overall revenue requirement should be reduced and which programs would need to be reduced or eliminated. Also included in the comments were requests to start the review of programs as far in advance of the rate proceedings so decisions will not have been made, with a subsequent review of outstanding issues prior to the rate case, much like PFR II.

BPA held the PFR process in order to examine with the public all the program costs recovered by rates in an attempt to find the right balance. BPA believes that all program areas were open for review and savings identified where appropriate. All commenters except one took responsibility for understanding BPA's power cost structure sufficiently to recommend specific cost reductions, rather than calling for an arbitrary $30 million in savings to hit a rate target. BPA further believes that the "serious discussion" of programs called-for in one comment has been occurring through PFR and numerous other public processes over the last four years. Through these public processes, each program has been looked at in light of BPA's mission and objectives, including the need to make BPA rates as low as possible consistent with sound business practice.

As for starting these types of reviews far in advance of the rate proceedings, BPA is pursuing this by embarking on the first agency wide capital review process in June 2006 which will look out to 2012. This timeframe was chosen to help the public understand and provide input on new capital approvals and their impacts on BPA finances. BPA is also addressing the long term cost review process in the soon to be released Regional Dialogue Policy Proposal.

Conclusion

The PFR processes provide a public review and comment opportunity concerning BPA's power program cost levels. These review processes provide a forum for BPA to work collaboratively with customers and constituents to seek the lowest-cost means of meeting BPA's mission objectives. BPA will prudently manage to the funding levels set in these processes and is committed to seeking continued feedback from the region. Communication with the region on cost levels is not just a one shot thing but an ongoing dialogue. BPA is committed to meeting regularly with interested persons to discuss program levels as well as to discuss further potential changes in costs.

PFR II Final Report Scorecard
Net Changes from the initial power rate proposal

The PFR II Scorecard below is designed to estimate the change to the revenue requirement and takes into account offsetting revenue impacts where applicable.

	PFR II: Areas of Priority Focus Average Annual FY 2007 - 2009 ($ millions)		
		Changes from Power Initial Proposal	
		+	-
1	**CGS O&M**		
2	Increases for additional maintenance (expense)	$ 14.6	
3	Decrease from fuel management savings		$ (16.7)
4	**Corps & Reclamation O&M**		
5	Benchmarking federal projects O&M against other regional hydro projects		$ 0.0
6	**Residential Exchange**		
7	None		
8	**Transmission**		
9	Review transmission expense for secondary sales		$ 0.0
10	**Fish and Wildlife**		
11	F&WL Monitoring and Evaluation (M&E)		$ 0.0
12	**"Other"**		
13	DSI $59 million annual support ($53M/yr is expected value in I.P. with risk)		$ 0.0
14	Review Spokane settlement status		$ 0.0
15	Trojan decommissioning costs		$ (1.2)
16	**Internal Operations**		
17	Examine potential for additional EPIP savings		$ 0.0
18	**Conservation**		
19	Consider conservation done by utilities "on their own nickel"		$ 0.0
20	Increase BPA funding for conservation	$ 0.0	
21	**Renewables**		
22	Remove Calpine geothermal net cost from 2009		$ (6.0)
23	Consider averaging facilitation costs and fund backstop in FY09	$ 1.4	
24	**Long Term Generating Projects**		
25	None		
26	**O&M Subtotal**	**$ 16**	**$ (24)**
27	**Estimated Capital Cost Recovery**		
28	Longer amortization period for conservation acquisition		$ 0.0
29	Longer amortization period for fish and wildlife investments		$ 0.0
30	Use BPA borrowing authority for land and water acquisitions for fish	$ 0.0	
31	Extend existing CGS debt to 2024		$ (16.0)
32	Longer maturity (to 2024) on debt for new CGS investments		$ (1.5)
33	Update to reflect 2005 actuals in repayment studies		$ (3.5)
34	Columbia River Fish Mitigation plant-in-service schedule -- DOD IG decision	$ 10.0	
35	Potential increases for CGS additional maintenance (capital)	$ 2.5	
36	Potential increase in interest credit due to improved FY06 financial results and direct pay		$ (10.0)
37	**Estimated Capital Cost Recovery Subtotal**	**$ 13**	**$ (31)**
38	**AVERAGE NET PFR II SAVINGS/INCREASE PER YEAR**	**$ (26)**	
39	**AVERAGE NET PFR I SAVINGS PER YEAR**	**$ (96)**	
40	**TOTAL PFR PROCESSES SAVINGS AVERAGE PER YEAR**	**$ (122)**	

Appendix A
Power Function Review expense only totals

The numbers in the table below represent the expense only portion of the various forecasts. It does not take into account any changes to revenues that may have occurred in conjunction with the expense change.

		PFR Base FY07-09 Average Forecast $ in millions	PFR I FY07-09 Average Final Report $ in millions	FY07-09 Average Initial Proposal $ in millions	PFR II FY07-09 Average Final Report $ in millions	Changes from PFR Base to Final Report $ in millions	Changes from Initial Proposal to PFR II Final Report $ in millions
1	Long-Term Generating Projects	$25	$25	$25	$25	$0	$0
2	Renewables Program (Expense Only)	$56	$42	$42	$37	-$13	-$6
3	Conservation Program (Expense Only)	$71	$71	$72	$71	$0	-$1
4	Internal Operations Charged to Power Rates	$116	$110	$110	$110	-$6	$0
5	Other*	$120	$105	$125	$124	-$15	-$1
6	Fish & Wildlife Direct Program	$139	$143	$143	$143	$4	$0
7	Transmission Purchases, and Reserve/Ancillary Services	$189	$184	$184	$184	-$5	$0
8	Settlement Payments to Residential & Small Farm Consumers of IOUs	$323	$323	$301	$301	$0	$0
9	Corps and Reclamation O&M for Hydro Projects	$242	$240	$241	$241	-$2	$0
10	Columbia Generating Station O&M for Nuclear Plant	$284	$263	$234	$232	-$21	-$2
11	Capital Cost Recovery	$1,003	$965	$979	$960	-$38	-$19
12	All Power Purchases (including Augmentation Purchases)	$107	$107	$167	$167	$0	$0
13	TOTAL	$2,674	$2,577	$2,623	$2,594	-$97	-$29

** Other includes: US Fish & Wildlife Lower Snake Hatcheries, Planning Council, Colville Settlement, Spokane Settlement, Trojan Decommissioning, WNP 1&3 Decommissioning, PNCA Headwater Benefit, Hedging/Mitigation, Other Environmental Requirements, Civil Service Retirement System, Other Income, Expense, Adjustments (DSI benefits for FY07-09)*