PFR-001
FEB 1 0 2005

Bonneville Power Administration
Power Function Review Workshop

January 25, 2005

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 55; 20 by phone

[The handout for this meeting is available at: www.bpa.gov/power/review.]

Opening Remarks

Paul Norman (BPA) welcomed participants to the Power Function Review (PFR) workshop and introduced Michelle Manary (BPA), project manager for the PFR. This is the start of an extensive public review of costs that will go into the 2007-2009 rate proposal, he said. BPA had a large rate increase in 2002, and the rate level starting in 2007 is of great interest to customers who pay the bills, as well as to those involved with BPA's public purposes, Norman said. In the PFR process, we are committed to talking to you about the costs that go into our rates and taking your input, he said. We will spend about four months sharing information, and we will look to you for ideas about how to keep costs as low as they can be and still meet our agency mission, Norman stated.

There are three tracks in this review, he continued: technical, policy, and regional public meetings. For the policy meetings, we have invited 35 management-level people to be committed participants, and we will hold those sessions about a week after the technical group meetings, Norman explained. The regional meetings in April will be held at various locations to give the public an opportunity to make input, he indicated.

The PFR will conclude at the end of April, after which BPA will make decisions about the costs that will go into the 2007-2009 rate proposal, Norman said. The 7(i) rate proposal will come out around September, he said.

Today, we will provide a "high-level flyover" of BPA's cost information, Norman went on. We also want to collect questions you have about the cost issues, so we can have productive discussions in later workshops that are sure to include what you want to know, he said. We also want your comments about the process and how we can be most responsive, Norman added.

Power Function Review: Opening Workshop Handout

P. 5: According to Norman, the desired PFR outcome is that "power rates reflect the lowest practical costs consistent with meeting BPA's objectives." We see that as the main goal of this effort, he said. Norman listed the following as what BPA would like to hear from participants when the PFR concludes: staff was very responsive to my information requests; staff was interested in my input and sincerely tried to respond to it; staff was clear about how my input would be used in making decisions; I understand the costs going into the BPA power rates and the reasons behind them; and BPA and its partners are very committed to making costs as low as they can reasonably be while accomplishing the agency's objectives. We are going to be asking you these questions, and we will measure our success based on your response, he added.

P. 6: Norman went over a list of major program areas that make up the bulk of BPA's power costs, from the largest of the nine, federal and non-federal debt service, to the smallest. We will talk about all of the items on the list; for some, the decision about the level of costs to include in the rate case will be made in the PFR, and for others it will not, he explained. We have indicated in parenthesis which decisions will be made in the PFR, Norman indicated.

P. 7: We've listed the costs that go into our rates, but there are other drivers as well, he stated. Norman listed the other drivers as: loads and resources; revenue credits, including secondary sales; reserve levels; rate design; and rate level. These items will be at issue in the rate case, but they are not topics for discussion in this process, he clarified.

P. 9: Norman explained "a simple equation" for calculating BPA rates:

$$\frac{\text{Costs - Credits + Risk}}{\text{Loads}} = \text{Rate}$$

The focus of the PFR is costs, the first element in the equation and the biggest driver, he said. But, as we said, it is not the only driver, Norman added.

You will want to know about the trends with our costs, so in the PFR, we will be looking at what has occurred over 12 years, he explained. Because of changes in our accounting systems, however, it may be hard to compare things exactly, Norman said. We'll do our best to make appropriate comparisons and to make things clear, he said.

P. 10: Norman moved on to a bar graph of BPA's actual and forecasted "nominal" power rates from fiscal year (FY) 1996 to 2006. In the 2002-2006 period, rates ranged from $30 per megawatt hour (MWh) to $32.7 per MWh, according to the graph. We are working on the bars for the 2007-2009 period and should have them soon, he said. In response to a question, BPA staff clarified that the rates on the graph do not include transmission, but power only.

The Record of Decision (ROD) from the Regional Dialogue hasn't yet come out, but can we assume you are not talking about tiered rates now? Steve Weiss (NWEC) asked. We will have the ROD out any day, Norman replied. Yes, you are safe in assuming we are not talking about tiered rates, he said.

P. 11-12: Changes in FY07-09 Credits and Loads.
This page lists drivers besides costs, including secondary revenues, revenue credits, and loads, that impact BPA rates, Manary explained. She said secondary revenues will be a major driver of rates in FY07-09; natural gas prices are expected to decline relative to today's market; less surplus is expected; and BPA needs to refill non-Treaty storage.

Norman pointed out that while market prices are forecast to be higher than in previous rate periods, actual revenues are expected to be about the same. Steve Oliver (BPA) explained the difficulty of comparing secondary revenues from past periods because of the Slice contracts. We end up with "apples and oranges" – it gets complicated and "would take another workshop to explain," he indicated.

Norman reported that due to low water years, BPA has exhausted its non-Treaty storage rights with Canada, and in time, will have to refill Canadian storage. "We are looking at the need to put water in Canada," and in FY07-09, it could be as much as 100 aMW a year, Norman said.

With regard to revenue credits, Manary said all the Fish Cost Contingency Fund (FCCF) is gone, and annual revenues from out-of-region contracts are down to roughly $200 million in FY07-09. BPA staff said out-of-region contracts, the largest of which was with SCE, had been terminated or the obligations diminished due to the drought in 2001. Participants asked BPA to provide an update on the exact status of out-of-region contracts.

FY07-09 loads are forecast to be about the same as actuals in FY02-06, Manary said. She explained a table listing the loads. Dave Hoff (PSE) suggested it would be helpful to have the out-of-region contract information and secondary revenues displayed together with loads to get "the whole picture."

Hydro generation has been changing over the last 10 years due to fish measures and efficiency projects, Manary pointed out. With regard to thermal generation, she said the Columbia Generating Station (CGS) has been generating at a level higher than forecast and is expected to stay higher in FY07-09.

How will the summer spill issue be treated in the rate case? Linc Wolverton (ICNU) asked. We have another track in the PFR on the topic of fish costs in rates, Norman responded. The spill issue will be decided outside the rate case, he said. Will the increased expenditures on maintenance in the hydro system show up in the unit availability forecast for the rate case? Jim Litchfield (LCG, Inc.) asked. We are investing a lot in the hydro system, Norman responded. With the investments, we have stopped the decline of facilities, and with efficiency projects, we are extracting more generation from the water that goes through turbines, he stated. These will be reflected in our rate case estimates, Norman said.

P. 13: Changes in FY07-09 Risk Profile.
The issues on this page relate to risk and are very important for the rate case, Norman said. We will talk about these a lot, he said.

Our cash reserves are down a bit from the FY02-06 rate period, Manary said. The expected value of the agency reserves at the start of the rate period is $350 million, based on estimates from the August 2004 Safety-Net Cost Recovery Adjustment Clause (SN CRAC) workshop, she said.

Manary listed the risks as follows: FCCF credit (no longer available to help in low-water years); minimum liquidity reserve level (level of working capital needed is probably larger); market volatility (greater variability than before in secondary revenues); new/modified risk (IOU benefit expense of between $123 million and $323 million annually); and the Treasury payment probability (TPP) standard (return to previous three-year target of 92.6 percent from 86 percent in the current rate period).

Lon Peters (PGP) asked for a breakdown of the TBL and PBL reserves. From my recollection of the TBL rate case, this PBL figure looks low, he said. Paul Murphy (MBLLP) pointed out that market price poses a risk in terms of secondary revenues and the IOU benefit expense. He noted that the market price should be consistent in both analyses.

P. 15-16: Expenses in Nominal Dollars FY97-09; Expenses in Real 2004 Dollars.
Manary explained a bar graph that presented BPA's costs from the FY97-01 rate case and '97-01 average actuals, the FY02-06 base rates and '02-06 average actuals, and the FY07-09 PFR preliminary forecast.

Hoff pointed out the disparity between rates and costs. It looks like your rates have gone up 50 percent, but your costs are up just 10 percent, he said. It's hard to make leaps like that from these numbers, since other factors, like swings in secondary revenues and FCCF credits, play a role, Norman responded.

What was the management direction in undertaking the PFR? Kevin Clark (Seattle) asked. Our direction was to establish the lowest level of cost possible and still meet our goals, Norman replied. We are testing this with you and asking whether we are there yet – are the costs as low as they can be, he said.

P. 17: Expense Breakout in Nominal Dollars.
Manary explained a graph with a breakout that compared average expenses for FY97-01, FY02-06, and FY07-09. Hoff pointed out that the ranges in the expense categories for FY07-09 are inconsistent. The comparison "mixes apples and oranges" since you used the maximum figure for the residential exchange, but not for other categories, like power purchases, he commented.

Will the residential exchange be an issue in the rate case? Wolverton asked. We are doing a paper that explains and discusses the exchange, and we will post it on the web, Manary responded.

P. 18: Expense Changes in Nominal Dollars from FY97-09.
Manary explained two tables that capture changes in expense levels for the two rate periods, FY97-01 and FY02-06, and the forecast for FY07-09.

P. 21: Components of the Forecasted Expenses in FY07-09.

Manary explained a bar graph displaying the major categories of expenses and the percent of total costs that each represents.

P. 22: FY07-09 Power Expenses, Long-Term Generating Projects.
These are contracted power purchases and most have offsetting revenues associated with them, Manary explained. The FY07-09 annual average expense for these projects is $25 million, she said.

Is there a way to get a list of the offsets to the generating projects so we can tell if they are cost effective? Weiss asked. Yes, we could provide the MW and KWh sales, Manary said. There was also a request for this information relative to renewables and conservation.

P. 23: FY07-09 Power Expenses, Renewables.
There are also revenue offsets for the renewable purchases, Manary pointed out. The jump in annual expenses from FY02-06 to FY07-09 ($22 million to $56 million) assumes purchase of power from Calpine's geothermal project, she said.

P. 24: FY07-09 Power Expenses: Conservation.
Manary explained the table of expenses associated with conservation purchases and the components of the $71 million annual expense projected for FY07-09. Over half is associated with the proposed conservation rate credit, she said. Clark said the process to resolve the rate credit isn't going well. I have gotten a report from the conservation collaborative, and "I'm more sanguine than you" about its prospects for success, Norman said. The participants want more time to work on the issues and are waiting until the Northwest Power and Conservation Council puts out its list of cost-effective measures, he said. Where will a decision be made? Clark asked. We will decide in May, and our decision will be informed by the PFR workshops and the collaborative, Norman replied.

P. 26: FY07-09 Power Expenses: Internal Operations Charged to Power Rates.
Most of this expense is personnel, Manary explained. The $116 million annual average, up from $107 million in FY02-06, is driven primarily by "people costs," she said. Total PBL staff is declining, Norman pointed out. Are there increases in the corporate FTE that offset the decrease in PBL staff? a participant asked. It's difficult to get at the corporate FTE dedicated to PBL versus TBL, Norman said. But we can share the trends in those numbers at the workshops, he offered.

How do you allocate costs of shared services between PBL and TBL? asked Lyn Williams (PGE). We can provide that information at the workshop too, Norman said.

P. 27: FY07-09 Power Expenses: Fish and Wildlife (F&W) Direct Program Only.
Manary pointed out that a series of workshops on F&W will address the issues related to F&W expenses. When are the opportunities to provide input on F&W costs? Bill Drummond (WMG&T) asked. "The main action" on this topic will be in Greg Delwiche's workshops, Norman responded.

P. 28: FY07-09 Power Expenses: Transmission Purchases & Reserve/Ancillary Services.
The $259 million in FY97-01 was driven by the ’01 drought, Manary noted. The $189 million estimated annually for FY07-09 will swing from year to year, she said. What is happening with the Corps and Reclamation costs to provide ancillary services for TBL? Clark asked. These are not costs that should be covered by PBL, he said. Oliver responded that the issue would be taken up in the rate case. There will be “a placeholder” in the rate proposal, and a calculation will be made in the rate case, he said.

P. 29: FY07-09 Power Expenses: Payments to IOU Residential and Small Farm Consumers of IOUs.
We will be doing a background paper on this – how the benefit was reached, the methodology, and so forth, Manary reiterated.

P. 31: FY07-09 Power Expenses: Corps and Reclamation O&M for Hydro Projects.
These costs have gone up, with an estimate of $242 million annually in FY07-09, Manary said. There are increased costs associated with things like security and the Biological Opinion, she said. The Corps and Reclamation will be here to talk to you in more detail at a workshop, Manary indicated. We will touch on Corps and Reclamation fish costs, but the details will be in the F&W workshops, she clarified.

How many employees are there at the Corps and Reclamation facilities? a participant asked. We will provide that information, BPA staff said. Will there be a discussion of recent investments in the hydro system and what they have provided in terms of unit availability? Peters asked. Yes, BPA staff responded.

P. 33: FY07-09 Power Expenses: CGS O&M for Nuclear Plant.
The increase in the FY07-09 period reflects two refueling years in a three-year rate period versus two refueling year in the previous 5-year rate period, Norman pointed out. Since refueling years are higher cost, this biases the 2007-9 average up, he said. Murphy said he would like to see the incremental costs associated with refueling year and Norman said BPA would ask Energy Northwest (ENW) to provide that information.

During the Sounding Board, BPA and ENW had differing views about the costs and benchmarks for the nuclear operation, according to Howard Schwartz (State of Washington). Will we get both points of view on that? he asked. I’m not sure there is much of a gap anymore, given the ENW cost management effort that is not yet reflected in the numbers, Norman responded. I’d like to know about how that gap was narrowed and find out if BPA is still thinking there could be some economies of scale if ENW were to become part of a larger organization, Schwartz said. We’ll pick up those topics, Norman responded.

P. 34: FY07-09 Power Expenses: Net Interest, Depreciation, and Amortization.
One of the risks with this expense is the change in plant-in-service schedule for the Corps’ Columbia River Fish Mitigation project, Peters said. What is that project? he asked. Val Lefler (BPA) explained that the project is made up of fish mitigation

facilities, like collectors and removable spillway weirs, at Corps dams. The intent was that once the project was complete, the costs would go into plant in service, she explained. But there have been delays, and there is uncertainty about when the costs will become plant in service, Lefler said. Is there a choice to put part of the project into service instead of waiting for the entire amount? Clark asked. There has been discussion of that, Lefler responded. She said the issue would come up at the Corps/Reclamation workshop.

Hoff asked BPA to provide more information about how increased capital investment would impact costs.

P. 35: FY07-09 Power Expenses: Non-Federal Debt Service.
The $566 million annually reflected here is associated with non-operating and operating generation projects, Manary said.

P. 36: FY07-09 Power Expenses: Impacts of Debt Management Actions.
The actions BPA takes with respect to capital affect PBL costs, and this chart indicates the upward or downward effect of various actions, Manary explained.

P. 37: BPA's Total F&W Program.
This is the total program cost versus the direct F&W program expenses displayed earlier, Manary said. The total cost is $691.6 million annually, she said, noting that at the F&W workshops, there will be discussions of the entire program.

Once again, I would ask you to break out the expenses associated with irrigation, municipal water withdrawals, navigation, and other river uses, Weiss requested. We've asked for this information "about 50 times," and "our request keeps being ignored," he contended.

We have provided this information relative to irrigation in the Sounding Board process last year and it is posted on the web, so I don't think we have been ignoring the request, Norman responded. This figure on the expenditures for F&W becomes very public – it gets into the press and utilities use it, Weiss said, adding that costs of other uses of the hydro system should get equal attention. "The power system does not own the river," he stated.

We need to see the costs of all non-power constraints to the hydro system, as well as any credits associated with them, Ed Sheets (Consultant to Yakama Nation) requested.

This table is not titled accurately, Geoff Carr (NRU) pointed out. These are just BPA costs – this doesn't include Grant PUD, PGE, and many others in the region that spend money on F&W programs, he said. I'd suggest you re-title it as just BPA costs, Carr recommended.

We need to understand the difference between the costs to operations and the use of direct program funds for on-the-ground measures, Litchfield said. He also noted that the table doesn't reflect costs of subbasin planning.

In the Sounding Board, BPA did some good work to get at the costs of irrigation, Schwartz pointed out. Some follow-up on the irrigation costs and revenues would be helpful, he stated.

If you could associate total F&W expenditures with fish benefits, that would be useful too, Murphy said.

It would be helpful to know at the end of the workshop, how the agency will go from the PFR to a rate proposal, John Saven (NRU) stated. It would be useful to know what the procedure will be and what our rights are, he said. How you get from here to the proposal is important for the credibility of the agency, Saven said.

P. 39: Planned Power Function Capital Expenditures for FY07-09.
This table breaks down the capital expenditures into categories, including Corps and Reclamation, F&W, and conservation, Manary said.

I'd like to see a list with specific plant-in-service information, including assumptions and dates, for each year, Clark said.

Also, it would be helpful to see a list of the capital investments deferred from the past that may be coming up again, Jeff Nelson (SUB) requested. It would be helpful to know what was submitted to OMB, Williams added.

Why isn't conservation expensed instead of capitalized? Weiss asked. I was of the impression that was going to happen, he said. This reflects the capitalization for ConAug through 2006, BPA staff responded. There are no decisions yet – these are assumptions, Norman clarified.

Could we revisit the decision on the amortization period (currently declining through September 2011) for ConAug? Clark asked. Yes, Norman responded.

<u>Power Function Review Schedule</u>

Norman called attention to the schedule for the Technical Workshops and Management Discussion Groups. What is the management group and how will it function? Sheets asked. The group is made up of management-level people; we will be making presentations and getting their input, Norman replied. It is not a decision group – we want to have back and forth about whether what we have done is all that we can do to keep expenses as low as possible, he said. We'll also provide an opportunity for written comments, and we will have a wrap-up session April 27 with Steve Wright, Norman stated.

This is similar to the Sounding Board, which had 20 people participating, he continued. But there will be more participants than the Sounding Board. Also, though BPA has invited 35 specific members, meetings will be open and anyone can attend, but we want to keep the discussions at the managerial and policy level, Norman said. He also said that the Management meetings were purposefully scheduled to come after technical meetings. He said BPA hopes that at least some Management Group members will be briefed by technical staff before the meetings, so that the Management Group meetings can be more meaty. He noted that most of the management-level meetings conflict with Northwest Power and Conservation Council meetings. If there are going to be schedule changes, could you let us know as soon as possible, Dick Helgeson (EWEB) requested. [The revised schedule has been communicated]

Where should we direct data requests? a participant asked. Direct them to me, Manary said: mlmanary@bpa.gov. We will post the questions and answers on the web site, she said. We will do our best to be responsive, Norman added.

Will you provide materials ahead of the meetings so we have a chance to review them? a participant asked. Yes, we will try to post the information at least two days before the meetings, Manary said. That generally means Friday before the Tuesday meetings, she said. Participants said it would be helpful to have more time, a week, if possible. She said BPA will do its best to get material out as early as possible. If you provide us your e-mail, we will notify you of the postings we make to the web site, Manary offered.

It’s a very short turn-around between the technical workshop on risk and the management discussion, Wolverton pointed out. Clark said meetings that start at 9 a.m. work better for those who have to travel to Portland. If the meetings start at 8:30 a.m., we invariably have to come in the night before, he said. [Meeting start times have been moved to 9 a.m.]

This is a good process that you have put together, “but it is fragmented,” Clark said. What are we going to do with all of this information – will there be a wrap up? he asked. We can add a summary meeting if you want, Manary said. The point is for us to hear from you – we want it to be a collaborative process, she stated.

Why did you reject the two-year rate case? Wolverton asked. There isn’t an official decision yet, but this process is probably a good forecast of what the ROD on the Regional Dialogue will say, Norman responded. With three-year rates, we are setting ourselves up to have to do rates at the same time we prepare new contracts for customers who want one, he noted. But a three-year rate allows us “to sync up” with the TBL rate period, Norman said. Under some scenarios the three-year period also allows lower rates than the two-year period, he said. The ROD will go into detail about the decision, he added.

In wrapping up the meeting, Norman said he was aware of the concern Saven raised and is sensitive to the dynamics. We can’t lay out a PFR road map in its entirety, but we tried to create clarity in today’s packet, and we’ll try to provide more clarity as we go along, he stated. Norman asked participants to fill out the feedback questionnaire to help PBL shape the process to work as productively as possible.

The meeting adjourned at 11 a.m. Next meeting: February 1, 2005.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on a ongoing basis. The Web address is www.bpa.gov/power/review.

1. Provide an update on the exact status of out-of-region contacts in relation to annual revenues from these contracts being down. In addition, it would be helpful to have the out-of-region contact information displayed with information on secondary revenues for a complete picture.
2. Provide a breakdown of the TBL and PBL reserves.
3. Provide a list of offsets to the generating projects and for conservation and renewables.
4. PBL FTE has declined. Has there been an increase in Corporate FTE to offset this decline?
5. How do you allocate costs of shared services between TBL and PBL?
6. What are the opportunities to provide input on Fish & Wildlife?
7. How many employees are employed at the Corps and Reclamation facilities?
8. The gap has narrowed between BPA and ENW on their views regarding costs and benchmarks for nuclear operation. How was that gap narrowed and does BPA still think there could be economies of scale if ENW were to be part of a larger organization?
9. Provide more information about how increased capital investment would impact costs.
10. Break out the expense associated with irrigation, municipal water withdrawals, navigation and other river uses.
11. Provide a list of the costs of all non-power constraints to the hydro system, as well as credits associated with them.
12. Explain the difference between costs to operations and the used of direct program funds for on the ground measures.
13. Provide an association of total fish and wildlife expenditures with fish benefits.
14. How will the agency go from the PFR to the rate proposal? What are our rights? How you get from here to the proposal is important to the agency's credibility.
15. Provide a list of plant-in-service information, including assumptions and dates for each year.
16. Provide information on capital investments that were deferred and may come up again.
17. What was sent to OMB?

FFR-002
FEB 18 2005

Bonneville Power Administration
Power Function Review Workshop
Transmission Acquisition Program

February 1, 2005

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 40; 18 by phone

[The handout for this meeting is available at: www.bpa.gov/power/review.]

Opening Remarks

Michelle Manary (BPA), manager for the Power Function Review (PFR), welcomed participants to the PFR workshop and introduced Margaret Pedersen (BPA), Leslie Pompel (BPA), Steve Oliver (BPA), and Ron Homenick (BPA). Manary stated that the handout for the meeting is on the Power Function Review Web site and that changes were made the day before (on pages 2, 9, 10, 20, and 25). She asked people to please fill out the feedback form after the meeting, as staff uses these forms to improve future workshops. All notes and questions from today's meeting will also be posted on the Web site, including any follow-up answers to questions generated in the meeting. BPA will also post any questions received via e-mail on the Web site. She also noted that the quarterly review is also posted on the Web site.

Power Function Review: Transmission Acquisition Program Handout

Pedersen began the review of the Transmission Acquisition Program handout. (Questions raised during the review are included.) The major purpose of this program is to obtain transmission services to deliver secondary and requirements energy.

P. 3: This page lists acronyms used in the program.

P. 4: This page shows how the program fits in the Power Business Line's "Balanced Scorecard."

P. 5: This page shows how program costs are included in the rate structure. About 7 percent of the expenses in the rate structure are from this program, but the percentage can vary with the amount of secondary energy. Actual numbers vary from the number forecast. This information will be updated for the PBL Rate Case.

Scott Brattebo (PacifiCorp) asked how much of the 7 percent could vary, that is how much of the $189 million. The answer will be posted on the Web site.

Linc Wolverton (ICNU) asked if PBL furnishes real power losses in this program.

Pedersen explained that PBL provides the real power losses across 3rd party transmission providers for Transfer Service Component and 3rd Party Transmission & Ancillary Services Component.

P. 6: The program represents costs associated with services necessary to deliver energy from resources, generation integration costs from Army Corps of Engineers and Bureau of Reclamation projects and a small component of metering and communication requirements.

P. 7: The program's goals are to achieve the least cost mixture of long-term and short-term products and to meet the Agency's transfer service obligation.

Jeff Nelson (SUB) asked if the costs of the non-wires measures are included in this budget. Pedersen stated that those costs are in the Conservation budget.

P. 8: There are five components of the program. For Transmission and Ancillary Services and Reserves and Other Services, the dollars flow to TBL. For Telemetering/Equipment Replacement, the dollars flow to TBL and also to third parties. For Transfer Service and Third Party Transmission and Ancillary Services, the dollars flow to the third parties.

P. 9: Of the five components of the program, two are 94 percent of the program: Transmission and Ancillary Services (67 percent) and Transfer Services (27 percent).

Linc Wolverton (ICNU) asked why, according to the graph, there was an increase in 2006.
Pedersen explained that these numbers were developed before the TBL rate settlement and are based on forecasts before August 18, 2004. The rate increase is in the 2005-06 period and so this chart is just for illustrative purposes only.

Lon Peters (PGP) suggested that it would be helpful to show which of these costs are fixed and which are variable. BPA will follow-up on this suggestion and post the information on the Web site.

P. 10: In the 1997-2001 period costs are higher than 2002-forward because transmission and ancillary services contracts expired in 2001. Old NT and NTP contracts (about $40-$45 million) dropped off at the end of 2001. There has been less secondary energy due to drier water years than FY 1997-2001 period.

Lon Peters (PGP) asked why there was a fall in the numbers for 2003-04.
Pedersen stated that part of the change was because the amount of secondary energy was lower in 2004 than in 2003. Another reason was due to an error in the TBL-PBL billing procedures which resulted in an over bill of roughly $11 million in 2003, in 2004 PBL received a credit of the $11 million.

Lon Peters (PGP) asked about the drop in 2004.
Pedersen said the surplus was lower by 30 percent that year.

Tom Karier (NWPCC) asked why 2001 was so high, was it because of the drought? Pedersen explained that BPA was still carrying transmission contracts for requirements customers and DSIs and acquired transmission to import from California in case BPA needed to. This resulted in more costs.

Doug Brawley (PNGC) asked if the variations are in secondary sales.
Yes, Pedersen answered.

Lon Peters (PGP) asked if in 2007-09, if BPA is assuming average water.
Pedersen said yes, but reiterated that the analysis uses 3000 variations in secondary energy, then takes the average of the resulting 3000 annual expenses.

Lon Peters (PGP) asked if the grandfathered contracts for the 1980s that would expire in the next rate period were reflected in the analysis or if there are any offsetting effects. Pedersen said as grandfathered contracts expire this may result in additional secondary energy and this is reflected in the forecast.

Pedersen said that in 2004 the amount is $150 million, in 2007 it is $183 ($33 million increase). The difference is because of different surplus assumptions, the TBL rate increase of 13 percent (about $25 million), and a $7 million increase in transfer costs ($4 million to Avista and NorthWestern Energy for open access; $3 million forecast at 2 percent/year escalation).

Steve Oliver (BPA) said it includes long-term transmission plus short-term transmission. He also said that BPA would like to share secondary energy levels but that BPA did not want to get into its management strategy for the Transmission Acquisition Program in these workshops.

P. 11: Secondary energy sales include grandfathered and committed and non-committed sales.

P. 13: Costs for 1997-2001 are higher because there was more surplus and BPA held contracts that terminated after 2001. There was a drop in 2001-02 because some pre-1996 contracts terminated, which reduced costs. The 2004 actuals and the 2007 forecasts have a rate increase of 13 percent. There are changes in surplus. BPA will provide the fixed vs. the variable costs.

Doug Brawley (PNGC) clarified that FY03 had an over bill of $11 million and that was credited back in FY04.

Dave Hoff (PSE) was confused if the graph on this page included the whole program. Pedersen said that it was the Transmission & Ancillary Services Component. The heading was missing the rest of the title.

P. 15: This page lists the risks for the program in FY07-09.

Linc Wolverton (ICNU) asked if this was net of transmission that was not contracted for. He is concerned about double-counting.
Pedersen stated that it includes a fixed amount and a variable amount and that PBL fills in with short-term transmission.

Linc Wolverton (ICNU) wondered if the $165 million was the short-term component.
Pedersen said that the $90-165 million is the whole portfolio and included the fixed costs. This is the range. PBL will post the fixed and variable costs as requested earlier in the meeting.

A participant asked about the averages used, if the average is an average over averaged water years or if it is the average of the 3000 runs (scenarios) used.
Pedersen said that it is a 3-year average of the FY07-09 annual average based on 3000 variations in the secondary energy. The lowest annual expense is $90 million; the highest is $165 million.

A participant asked about the assumptions used.
Pedersen noted that no changes due to Grid West were accounted for.

Doug Brawley (PNGC) asked if the fixed contracts had varying lengths for their contracts and if there is a range of periods for fixed and variable costs.
Pedersen said that is true.

Dave Hoff (PSE) asked what is varied and why 3000 runs are done instead of 30.
Pedersen said that the 3000 runs vary hydro, loads, and nuclear production.

Jeff Nelson (SUB) asked if the same water years are being used or if they have been updated.
Pedersen said it is probably the same water years, and she would find out. The 3000 secondary energy years are used.

Michelle Poyourow (PPC) asked if the 3000 runs are weighted.
Pedersen will check and see if they are.

Steve Weiss (NWEC) suggested that the functionalization of costs of non-wires should be energy savings in the conservation budget, but the reliability portion should not be in the conservation budget.

Linc Wolverton (ICNU) wanted to know if the non-wires capacity charges go to PBL or to TBL.
Pedersen did not know and said she would find the answer.

Lon Peters (PGP) noted that some of the risks appear to be quantified and some are not.

Pedersen said of the 3000 scenarios, they use the average of the expenses across the 3000 variations for the forecast. The changes in transmission rates assume a 3 percent escalation for the last 2 years of the PBL rate case. PBL did not put in a number for congestion costs. For limited access, we assume a fixed percentage for hourly non-firm transmission and the fix percentage does not vary by scenario.

Lon Peters (PGP) asked what would cause PBL to purchase more expensive transmission products.
Pedersen gave an example of times when there are cutplane restrictions and it forces more expensive purchases. The transmission system is getting more constrained. The analysis includes a certain amount on the hourly market, which is more expensive.

Linc Wolverton (ICNU) asked if this was the same as redispatch and could you substitute.
No, Pedersen said, it is not an offset for buying transmission. Regardless on generation source we still need to by transmission.

Paul Murphy (MBLLP) asked if there is some or will be some consistency between TBL and PBL on a rate increase and higher secondary energy.
Pedersen said no, we have not coordinated with TBL.

Jeff Schlect (Avista) asked if the average is $125 million, what is the median?
Pedersen will provide that information.

Pedersen continued with the discussion of the page and said that they did not assume any scheduling structure changes in the analysis.

Scott Brattebo (PacifiCorp) asked how much secondary sales of long-term firm are factored into the runs.
Pedersen said the long-term transmission purchased from BPA go to a certain point like John Day. The analysis assumes we can use the transmission inventory and redirect it. Oliver said that not being able to redirect long-term firm would be a risk and costs would go up.

P: 16: This pages gives the ways PBL tries to manage costs.

Paul Murphy (MBLLP) asked if PBL sells transmission on the secondary market and if so would it show up as a revenue?
Pedersen said that PBL would like to, and how it would show up would depend on how it was done. If PBL used reassignment, it would reduce transmission and ancillary costs, but increase third party costs. There should be a net reduction in the overall Transmission Acquisition Program expenses.

P. 18: This page shows the methodology for the Transmission and Ancillary Services Forecast. What it doesn't include is transfer service, transmission from third parties and requirements contracts.

P. 20: This is one of the pages that was changed before the meeting.

P. 21: This page shows one run and what the output looks like. The fixed and variable costs will be broken out and posted. This includes long-term plus incremental transmission.

Michelle Poyourow (PPC) asked about a Bureau of Reclamation revenue credit.
Pedersen explained that old contracts with the Bureau pays BPA's revenue (for delivered power for some cases). PBL and TBL have agreed upon a split of 75 percent to PBL and 25 percent to TBL. TBL bills PBL for the 25 percent. We will provide more details of types of contracts.

P. 22: This page shows a standard expense calculation.

Dave Hoff (PSE) asked when the losses show up in the calculation.
Pedersen said that PBL self-supplies its own losses and we can't return losses to ourselves.

P. 24: This page starts the review of the Transfer Service Component. This component is about 27 percent of the budget.

P. 25: Pompel noted that the graph on this page has been updated. The difference is the 2005-06 figures were submitted in August 2004. For FY07-09 we are using FY04 actuals and a 2% inflation rate.

P. 26: This page lists the major drivers of changes including contracts expiring or being converted to OATT.

Linc Wolverton (ICNU) asked if any penalties for energy imbalance are forecast.
No, Pedersen said, the forecast assumes all costs and credits offset each other and net to zero.

Lon Peters (PGP) asked if the costs are not jumping, including the conversions.
Pedersen said they are not jumping.

P. 27: This page lists the risks associated with the Transfer Service Component.
Included are the associated costs for upgrades. This could be a fairly large number in the future, perhaps several millions of dollars. PBL is discussing whether these costs should be expensed like an asset would be or pay in the year PBL is invoiced.

P. 29: This page shows the methodology for forecasting the GTA budget.

Lon Peters (PGP) asked if contracts are converting to OATT, isn't it long-term transmission?

Pedersen replied that yes, it is more than 1 year. PBL assumes it is buying NT service. We take the actual load in the hour of the system peak. PTP should be somewhat equivalent to that. PBL normally purchases NT service. We do not know the load ratio share exactly, but using PTP is our best alternative.

Lon Peters (PGP) asked if PBL is assuming it can self supply ancillary services. Pedersen said no, we purchase where we can and we are not required to buy operating reserves.

P. 30: This page shows the Third Party Transmission and Ancillary Services Component. This is a small percentage of the overall budget and is payment to external entities.

P. 32: This page shows a graph of this portion of the budget.

Lyn Williams (PGE) wanted more information about the major drivers of change for this component.
Pedersen said the reassignment of transmission rather than remarketing of transmission reduces program expenses, though reassignment of some transmission caused actuals to go up. Over time reassignment will cause this component to go up, but not overall costs to go up. It is a small component of the program and you could likely ignore it.

P. 33: This page gives the reasons for changes in expense levels over time. For example, constraints on the transmission system will show up as an expense as outages in La Grande require PBL to go through Avista or another utility to serve loads.

P. 34: This page shows the risks associated with the Third Party Transmission and Ancillary Services Component and how PBL is trying to manage costs through maintaining staff expertise.

P. 36-37: These pages list the long-term transmission contracts for generation sources and other expenses.

Linc Wolverton (ICNU) asked if PBL is paying for losses on Greensprings.
Pedersen said that PBL does compensate PacifiCorp to get the energy.

P. 38: Homenick (BPA) reviewed the Generation Integration costs. These costs are associated with TBL assets for the transmission facilities between the generator and the network. The last Power Rate Case reflected recent FERC rulings that assigned generation integration costs directly to generation. The generation integration costs from Corps and Bureau of Reclamation projects are already rolled into their generation costs. The TBL integration is not in these costs and is left for the TBL rate case. Both business lines had 2002 rate cases, so power rates reflected TBL's 2002 and 2003 generation integration costs; 2004 and 2005 were developed in TBL's 2004 rate case. The 2006-07 TBL rate case is the latest. The TBL 2008-09 rate case is still to come, so the costs for those years will be determined at that time. There are some inter-business line transfers that provide revenue credits to PBL. There are a few Bureau and Corps projects where

PBL bills TBL for network and delivery transmission costs. PBL quantifies it in the rate case and then bills TBL and they include those costs in transmission rates.

P. 40: Where the costs have been in recent history is difficult to quantify based on the billing and the old financial system. Since 2002, costs are better defined. In 2001 there is a lump sum reflecting 1997-2001. Costs are at $8-9 million and are expected to be at that level based on a certain view of costs that went into TBL's preliminary rate calculation. It is not a totally calibrated rate for 2006-07 since the rates and charges were agreed to as part of the settlement of the TBL rate case.

Lyn Williams (PGE) asked about the change in 2006-07.
Pedersen explained the 2006-07 numbers are from the August 18 review and are a prediction. Then TBL settled its rate case.

P. 42: The risks to cost levels are from adding or replacing facilities, and higher inflation for O&M costs. PBL tries to manage costs but generation integration costs are set in the TBL rate case, and PBL has no direct control over those costs.

P. 43: This page shows the Telemetering/Equipment Replacement component of the budget. This includes metering and communications costs for open access if needed.

P. 44: This page states that new meters are sometimes needed to provide the kinds of data needed to meet business requirements.

P. 45: This page shows a graph of these expenses. They are not a large part of the budget. The graph was based on Grid West assumptions that will now likely change and so expenses will likely go down.

Appendices (starting on P. 48).

This appendix contains the methodology for grandfathered contracts. There is an average of 1320 MW on the network. The average intertie is 117 MW. It varies by month, and some terminate over time. There is some growth, but not much turnover during this rate period. The Canadian Entitlement is roughly 1100 MW. About 643 MW was converted to open access. PBL will make the Statement of Principles available.

P. 50: This page shows the assumptions and calculations used. The usage factor is low (about 45 percent), contracts are not often taken in light load hours or weekends.

P. 54: This page shows pre-purchased long-term transmission. In 2007-09 there would be about 1662-1665 MW. The numbers are also posted on OASIS. This graph shows what PBL would need over the years. PBL would fill in the difference between secondary and long-term transmission. The pre-purchased is as of today.

P. 55: This page shows pre-purchased long-term transmission over the TBL Intertie. There are 900 MW on the COB and 300 MW on the NOB.

P. 56: This shows what the contract demand for OATT PTP is based on and the expense calculation. PBL does not assume that it buys any incremental long-term or short-term transmission because there is none to be purchased.

P. 59: PBL assumes a usage factor of 60 percent because it may only be used in heavy load hours and not used 100 percent.

Lyn Williams (PGE) asked what proportion of the contracts are grandfathered vs. OATT. Pedersen will see about supplying this.

Paul Murphy (MBLLP) asked the amount of grandfathered contracts on the Intertie. Pedersen said for 2007, it is about 117 MW; for 2009, it is about 63 MW. Some contracts have been converted to OATT.

Wrap Up

P. 47: This is the wrap-up page. PBL would like feedback on the program levels and welcomes suggestions for these workshops. PBL is trying to keep costs low.

Manary asked that any follow-up questions be sent to her and she would distribute them to be answered and posted to the Web site.

Lon Peters (PGP) asked to what extent PBL buys PTP rights from other than TBL and if there is an opportunity to save some money there. This should be reflected in the risk variables.
Pedersen said the PBL does buy secondary transmission from other PTP holders, it depends on the pricing. We do not assume purchases in the forecasts, but they are reflected in actuals.

Jeff Nelson (SUB) asked for PBL to display what issues will not be in the Rate Case, so he knows what to pay attention to now.
Manary said she would post this information.

The meeting adjourned at 11:40 a.m. Next meeting February 8, 2005.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on a ongoing basis. The Web address is www.bpa.gov/power/review.

1. Page 5 of the handout shows how program costs are included in the rate structure. About 7 percent of the expenses in the rate structure are from this program. How much of the 7 percent could vary, that is how much of the $189 million.
2. There are five components of the program. It would be helpful to show which of these costs are fixed and which are variable.
3. On slide 13 the 2004 actuals and the 2007 forecasts have a rate increase of 13 percent. There are changes in surplus. Provide the fixed vs. the variable costs.
4. Are the 3000 runs weighted?
5. Do non-wires capacity charges go to PBL or TBL?
6. On page 15 what is the median costs for the FY07-09 period?
7. Provide the principles for Grandfathered Transmission.
8. What proportion of contracts are Grandfathered vs. OATT?
9. What issues will not be in the rate case so we know what to focus on now?

PFR-003
MAR 0 2 2005

Bonneville Power Administration
Power Function Review Technical Workshop
Conservation and Renewables Costs

February 8, 2005
BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 40

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

Opening Remarks

Michelle Manary (BPA) went through several housekeeping announcements and thanked participants for questions submitted after the last workshop. We will post all of the questions on the website along with our responses, she said. Manary also noted that handouts for the March 1 workshop would be posted later than usual due to a management-level meeting February 28.

A.M. Agenda: Conservation

John Pyrch (BPA) began his presentation on BPA's conservation programs and initiatives with a run through the discussion outline. He noted that BPA has been involved in conservation for over 20 years. I won't go through the background, but there is information about regional and BPA accomplishments in the handout, Pyrch said.

PBL's "balanced scorecard" supports the conservation program, he said, reading several pertinent statements from the 2005-2011 strategy map developed last summer. A statement labeled PF S3, for example, states that BPA "ensures development of all cost-effective energy efficiency in the loads BPA serves, facilitates development of regional renewable resources, and adopts cost-effective non-wires solutions to transmission expansion," Pyrch said.

BPA's Record of Decision (ROD) for the Regional Dialogue issued last week contains five principles BPA will pursue in its conservation program, he continued. Among the principles, "BPA will use the Council's plan to identify the regional cost-effective conservation targets upon which the agency's share (approximately 40 percent) of cost-effective conservation is based," Pyrch said.

Kevin Clark (SCL) asked about the treatment of investor-owned utilities (IOUs) under that principle. Does it figure them in? he asked. No, it doesn't, Pyrch responded. Clark pointed out that if the IOUs are eligible for the conservation and renewables discount (C&RD), it's as though BPA is serving another 2,200 MW of load.

Steve Weiss (NWEC) said since the IOU customers in effect help pay for the conservation BPA does, they should get the benefit of participating in the programs. But Kevin O'Meara (PPC) questioned that view, saying it presumes conservation is "a dead weight loss" rather than a resource. There are two pieces to it, Weiss responded. Conservation helps everyone since it reduces the need for resources, but "if I am paying in rates for a program, I should be able to participate in the program," he said.

The IOUs benefit from conservation by the fact BPA is not acquiring new resources, O'Meara said. If IOUs are eligible for C&RD, it would be transferring money from publics to privates, he indicated.

I'd like to see the math on this principle, with the assumed IOU and DSI service levels, Clark requested. Pyrch said that could be provided.

Pyrch moved on to the second principle, which states that "the bulk of the conservation to be achieved is best pursued and achieved at the local level," and the third, "BPA will seek to meet its conservation goals at the lowest possible cost to BPA."

Does the cost-effectiveness principle rule out partial payment for measures? Clark asked. That's right, Pyrch said. If a measure is not on the Council's list of cost-effective measures, we won't pay an incentive, he said. Pyrch noted that the conservation work group recommended making partial payment for some measures that are not on the Council's list of cost-effective measures, but BPA has not adopted that position. We plan to respond to the work group recommendations and will put our post-2006 conservation proposal out for comment, he added.

Is your statement on "lowest possible cost to BPA" a reference to the agency or to your end-use customers? Jim Litchfield (LCG, Inc.) asked. It's both, Pyrch responded. BPA as an agency, is the first consideration, but we will strive to keep costs low for the region, he stated.

Pyrch went over the fourth and fifth principles, which relate to BPA's aim to provide appropriate levels of funding for local administrative support, as well as education, outreach and low-income weatherization.

Do the low-income weatherization programs have to be cost-effective? O'Meara asked. No, they don't, Pyrch responded. So that is a departure from your cost-effectiveness principle, O'Meara commented.

"Low-income weatherization has extremely high non-energy benefits," so it is cost-effective, Weiss responded. I was just pointing out that there are exceptions to the cost-effectiveness principle, O'Meara said. The work group recommended low-income weatherization be eligible for rate credit money if the measures are cost-effective, Pyrch noted.

What is the process for determining the appropriate levels of funding referred to in the principles? Weiss asked. This workshop is part of it, Pyrch responded. At some point, could you make clear what decisions are being made here, Clark requested.

Many substantive decisions are being made elsewhere, Michael Early (Alcoa/CFAC) pointed out. The Council set the conservation targets and cost-effectiveness standards, and there was a prior work group, he said. What is movable in this process? he asked.

I am going over the 2007-2009 budget, and we will take your input and feedback, consider it and get back to you with a response, Pyrch clarified. He went on to explain a table of delivered and planned savings from BPA's existing conservation programs. We are on target to meet 220 MW of conservation during this rate period, Pyrch said. The savings are a result of the C&RD, ConAug, market transformation, low income weatherization and federal reimbursable programs, he pointed out, adding that the fiscal year (FY) 2001-2004 savings are actuals and the 2005-2006 are projections.

Does this incorporate price-induced conservation? O'Meara asked. It does not, Pyrch responded. Will you generate an estimate of price-induced conservation? O'Meara queried. We are looking at what we call "naturally occurring" conservation, Pyrch replied.

You have "jacked up" rates 40 percent in recent years, and it is having an effect on consumption, O'Meara stated. That should be counted, he said. As long as BPA rates are above 22 mills, your loads will be down, O'Meara added.

Asked about the kind of participation and success BPA is seeing in its programs, Pyrch said all but one of BPA's utility customers is participating in C&RD. About 22 percent of the customers reporting accomplishments have used all of their available C&RD credits and 20 percent have used over 80 percent, he reported. With ConAug, we have 65 contracts with 40 to 45 customers, Pyrch said. He said he would provide more information on the accomplishments of the program.

Pyrch went over a table of the regional conservation acquisition targets. According to the Council targets, the region needs to come up with 700 MW of conservation during the 2005-2009 period, he said. Of that, 40 percent or 56 aMW per year is BPA's share, Pyrch explained.

Weiss suggested BPA's calculation of its share should include load growth for partial requirements customers. Why limit the target to the load you serve? he asked. Why not figure in the load growth for partial requirements customers since it's likely to come back to BPA, Weiss said.

O'Meara said the PPC allocation scheme uses 2002 load numbers so conservation activities would not decrement a utility's share. Load growth would be exposed to "the full price signal" so there's even greater incentive to do more conservation, he explained.

That may be the PPC proposal, but BPA hasn't accepted it, Weiss responded. If BPA intends to adopt it, perhaps the agency could declare that intention, he added.

Litchfield suggested BPA take a closer look at the 56 aMW target. “That’s a simplistic view of the world,” he said, noting that conservation potential varies across the region. We recognize the potential isn’t equally distributed throughout the region, Pyrch acknowledged. We’ll “drill down” into that number and see how best we can meet the target, he said. Could the 56 aMW change based on a more realistic breakdown of what’s available? Litchfield asked. “That’s a tough one,” Pyrch replied. We’ve talked to the Council about that, but the question is unresolved, he said.

Mark Thompson (PPC) asked about the lost vs. non-lost opportunity conservation potential for various customer sectors depicted on Pyrch’s bar graph. Tom Eckman (NPCC) said the Council did not identify lost opportunity for the agricultural and industrial sectors because new development in those areas “is probably already price responsive.” But in the commercial and residential sectors, information is key, and it takes time for new programs to penetrate the market, he said. Greater penetration will occur over time as the programs ramp up, Eckman explained.

The non-lost opportunity targets don’t increase because they reflect the most we think we can get, Charlie Grist (NPCC) added. We limited the maximum rate of acquisition in those sectors to what we thought was practical, he said. Also, as we use up the cheaper energy efficiency measures, the rate of penetration falls off, Grist said.

Pyrch reviewed a graph of BPA’s annual delivered conservation savings and the 2007-2009 targets. We are aiming for 40 MW in 2006, which is below the Council’s target, he pointed out.

How do you propose to achieve the 2006 target? Clark asked. Industry will be a focus, and we will try for more industrial ConAug, making additional investments there, Pyrch replied. We are also thinking about new initiatives – we might do another compact fluorescent coupon program, for example – we’re looking at a lot of ideas, he said.

You’re now 16 MW per year behind the Council’s target, Weiss pointed out. How do you propose to catch up? he asked. Should you target more than 56 aMW in 2007-2009? Weiss queried.

We won’t necessarily meet the target in every year, but we’re proposing to meet the total amount over the rate period, Pyrch replied. We’ll have to see where we are as we go along and make adjustments, he added.

BPA made a commitment to meet the Council target so you should ramp up to meet an additional 30 MW beyond what you are targeting in the next couple of years, Weiss said. “It’s cheap stuff,” and we should go after it, he indicated. Comment noted, Pyrch replied.

My comment on price-induced conservation applies here, O’Meara said. Rate increases decrease loads – “it may be a destructive way to do it,” but that’s what happens, he stated.

With regard to the conservation target, Eckman said the Council took in to account changes in markets and rates since the last plan was developed. We are going from where we are today, he said. We don't count load curtailment, Eckman acknowledged. If people are induced to reduce load, it's not called conservation, he stated.

Why don't you count it? Early asked. If a price increase causes me to move a plant to Georgia, why don't you account for that? he queried. Under the law, we count things that make you more efficient, not things that cause you to reduce load, Eckman responded. The underlying price forecast incorporates loads and rates – "price elasticity" is taken into account in that way, he added.

There is a distinction between measures to be more efficient and things that reduce load, Howard Schwartz (WA CTED) said. The Council's job is to look at efficiency measures that would be cost-effective compared to something else, he said. Schwartz also pointed out that trying to figure out BPA's share of reduced demand would not be an easy task nor would determining how much reduction was due to BPA rate increases and how much was due to other factors.

Pyrch said BPA is boosting its 2006 target to 40 MW from 22 MW to keep up the pace of conservation. It's not something you can easily turn off and on, and we don't want to go through "the roller coaster" again, he said.

If you have programs that are successful going on now, "why reinvent them," especially in the middle of a 10-year contract? "Why fix what ain't broken," Clark asked.

The conservation work group recommended keeping things more similar than dissimilar to what we have now, Mike Weedall (BPA) responded. We think we can improve the products we're offering, he said.

BPA reduced its conservation program and staffing in the late 1990s, Pyrch said, presenting a graph of staffing numbers since 1993. In 1993, BPA had 233 full-time positions and 100 contractors on its conservation staff; by 2000, those numbers were down to 60 and 6.5, he pointed out. We're in "a steady state" now, and hope to stay that way into the next rate period, Pyrch said.

I'm nervous about your ability to meet the conservation targets with the same FTE you now have, Weiss said. I'd like to talk about "a backstop" in case your ambitious plan fails, he said.

If you look at BPA's delivery of conservation and the staffing levels, it's clear that staffing is not a good indicator of achievement, Litchfield pointed out. You went from 5 MW in 2000 to 53 MW in 2002 without a change in staffing level, he said. We've gotten very creative and collaborative with our conservation partners, Pyrch responded.

But less staff has meant there is no regional tracking going on, no evaluations and no research and development, Eckman responded. Be careful about thinking you can continue a rigorous program with this lower staffing and budget level, he advised.

Pyrch went over a graph illustrating the conservation component of the PBL expense level. An annual conservation expense budget of $71 million is 3 percent of the total $2.5 billion to $2.7 billion total PBL expense budget, he said. Succeeding tables showed the breakdown of expenses among conservation programs.

Weiss said the tables should reflect revenue generated by conservation. You should figure out how much money the program generates and credit it against the program costs, he suggested. Clark asked for the math behind the C&RD breakdown ($30 million conservation, $6 million renewables) on the program expense table. Pyrch said he would provide it.

The tables on pages 11-13 display historical and projected 2007-2009 expenses, as well as program components for the new rate period. The FY 2007-2009 expense budgets are open for review, comment and discussion in the PFR, Pyrch said. Page 14 provides the historical and projected FY 2007-2009 conservation capital budgets. Again, the FY 2007-2009 capital budget is open for review and comment under this PFR process, Pyrch said. In response to a question about whether the conservation target is open to discussion, Pyrch called the 56 aMW "a given." We said in the Regional Dialogue ROD we would go with the Council's target, he stated.

You made that decision before you knew what the measures would be, Jeff Nelson (SUB) commented. The Council had a two-year public process when it developed the targets, Pyrch pointed out. It was a regional process open to participation, he said. But not everything was resolved in it, Nelson said. "We're comfortable with what the Council put forward," Pyrch stated.

We worked closely with the Council, and we didn't hear in any of the groups that people thought the potential was unrealistic, Weedall added. "We think we've been down that road," he said of developing the target.

The issue of an appropriate target is linked to the measures and that is linked to funding, Nelson said. If you say the target is 56 aMW, other issues need to be resolved before we say we have a reasonable program, he indicated. Nelson also said there is a disparity between the BPA numbers and what utilities are expected to achieve.

We have said we'd accept the Council target for our share of what should be done with conservation, Weedall said. Let's work on whether we have the right mix of dollars and programs to meet the target, he urged.

What's negotiable here? Scott Brattebo (PacifiCorp) asked. We're looking for input on these budget numbers, Pyrch responded. Some may think we don't need as much money, others may think we don't have enough, he added.

Pyrch went through the historical numbers for the conservation program, categorized into five major groups of expenses, and budget projections for the 2007-2009 rate period. He also explained the types of expenses the categories include. From 1997 through 2006, we will have spent $579.2 million, and the 2007-2009 projection is $253.6 million, Pyrch reported. He said BPA is locked into some expenses, including the legacy contract closeouts, debt service payments, the low-income weatherization program (through 2006), and market transformation (through 2009) but others are open to discussion.

Weiss said TBL should pay for the savings related to non-wires solutions, and Pyrch said TBL pays for its share of the savings from several non-wires measures, including load control and demand exchange.

Asked how BPA would achieve the 56 aMW annually, Pyrch said bilateral contracts, a rate credit and market transformation would be the major program components. What would you get from low-income weatherization? Nelson asked. Those programs are run through state community action agencies, and "we view the savings as incidental," Pyrch responded. We met with these groups and heard "a strong plea" for more funding, so we have tried to build in more, he added.

Pyrch went over the conservation program capital budget, which is projected to be $32 million annually for the 2007-2009 rate period. Early asked for a table that would display the total conservation program, expense and capital, together. Staff agreed to provide the table. Pyrch explained how BPA arrived at $32 million in capital for conservation acquisition in 2007-2009. He noted that BPA wants the flexibility to move money between years and between conservation programs.

Has the treatment of the rate credit been decided? Litchfield asked. Pyrch said it had not. We'll follow up on that issue, he said. It's a fundamental question, Litchfield said. If the rate credit is changed to be part of the revenue requirement it means everyone pays you for it, and it sets up "a different psychology," he stated. You need to pay attention to how this is handled, Litchfield advised.

Is there going to be a decrement associated with the C&RD for customers? Clark asked. Weiss said Steve Wright told participants in a recent meeting that BPA wants to decrement a customer's purchase amount on the basis of the C&RD. "This is an active and ripe issue within the agency," Weedall stated. I can't tell you what's coming down the road on it, he said.

This is a question of "who's money this is" and that should bear on the response, Eckman commented. If you move the rate discount to the revenue requirement, it creates a different perception, he added.

Manary said she would find out in what forum the decrement/non-decrement, in/out of revenue requirement question would be decided. And find out if it applies to fixed purchase and/or full service and other contracts, Terry Mundorf (WPAG) requested.

Later in the meeting, Pyrch said BPA would issue its post-2006 conservation program proposal in mid-April. We will deal with the decrement and revenue requirement issues in that proposal, he reported. Pyrch said the proposal would also clarify the size of the rate credit. We will take 30 days of public comment on the proposal, and the decision that results will go into the rate case, Pyrch explained.

The outcome of those questions has implications for how much money it could take BPA to get to its conservation targets, Weiss commented.

It is not "customer friendly" to separate the issues out and split them into another process, Clark said. Mundorf suggested BPA have a meeting when it releases the proposal to explain it. That's a good suggestion, Pyrch agreed.

Pyrch continued his presentation with a list of conservation program challenges and risks. He said BPA staff is working with Council staff to come up with a figure for how much naturally occurring conservation is taking place and determining whether that should affect the target. Litchfield suggested BPA rethink the target, looking at its customer groups. The 56 aMW may not be accurate given the makeup of your load, he said.

I can accept your optimism about meeting the conservation target with the 2007-2009 budget proposal if there is a process to re-evaluate if it doesn't happen, Weiss said. We need a backstop or a robust program, he stated. If you want to talk about a backstop, you have to reassess whether the 56 aMW is appropriate, Mundorf stated. That hasn't been done, he added.

Among the risks, Pyrch said BPA will be asked to fill in the amount if customers under-perform on delivering savings. We want to manage the delivery of MWs so that doesn't happen, he added. Stephany Watson (Krogh & Leonard for PGE) asked if the request for BPA to fill in was related to a contract commitment. Pyrch said it was not a contract, but a political issue. There is a risk and expectation that we need to be aware of, he responded. Is there a history of this happening? Watson asked. If you look at the table on page eight, you will see that conservation delivery went way down when BPA cut back its program, Pyrch pointed out.

He went over a list of cost-management opportunities. Among the opportunities, Pyrch said program costs would go down if BPA's future rate credit mechanism is based on what it costs to get measures installed rather than on the value to the system.

Pyrch wrapped up with the feedback BPA has gotten on its post-2006 conservation budget. The work group recommended a budget of $80 million a year to acquire 56 aMW annually, with an additional $1.6 million per year for infrastructure support, he said. There is significant concern the budget will be insufficient to meet the target, and the work group said BPA should be willing to adjust funding upward if progress toward the target lags, Pyrch said. The work group also offered a proposed program structure for post-2006, he noted.

Pyrch's handout recapped comments, including a joint comment from several entities that $106 million per year is likely to be needed to achieve the new target. PPC commented that the conservation acquisition budget should be revisited once a cost-effective measure list is available; PNGC supported the work group's recommendation (Eugene Rosolie (PNGC) clarified that PNGC viewed the $80 million as a ceiling on the conservation budget); and SCL said BPA would have trouble meeting its new target if it spends part of the $80 million on measures that are not cost-effective.

When will a decision be made on the budget? Schwartz asked. We'll take PFR comments until April 29, so "speak up now," and final budget decisions will be made after that, Pyrch indicated. He also reiterated there would that BPA will issue a post-2006 conservation proposal for public comment in mid-April.

This is just 3 percent of "the total big picture," Geoff Carr (NRU) pointed out. We may come back later with other comments once we have seen all of the pieces, he said.

I can't find a correlation between your historic budget numbers and what you have achieved, Early commented. I can't tell if your budget levels are reasonable or not, he said. Early suggested BPA provide a table to help people connect the budget levels to results. What if the market is lower and you have to cut the budget? he asked. Could you find 10 percent to cut in this budget? Early asked.

If you look at what happened in the last few years, when the Administrator asked us to do just that, you'll see "we've been very creative" and managed to achieve a lot, Weedall responded. What you see here is a balance of a lot of things – trying to connect staffing levels to MWs achieved is comparing apples and oranges, he indicated.

Has there been benchmarking of staff levels? Early asked. We can share things with you from around the country, "and we'll come out looking good," Weedall responded, noting that BPA's staff of 60 operates a larger program than the staff of 150 he managed at a retail utility.

Is there reason to believe that what has historically been accomplished at a cost higher than $1.43 million per MW can be made to work at this budget level? Schwartz asked. BPA needs to do a good job of showing it can get the job done at this level – "I'm skeptical that it's enough," Schwartz said.

If the IOUs participate, do their savings contribute toward the 56 aMW? Brent Barclay (Columbia River PUD) asked. No, they are not part of the load we serve, Pyrch replied. Barclay suggested that, depending on how the C&RD is handled, more money could go out, leaving less to pay for achieving the 56 aMW.

There are a lot of reasons conservation does or does not happen, Rosolie said. To say the reason is one particular thing is wrong, he said. In the same way, being wedded to 56 aMW is wrong, according to Rosolie. We need to be aware that there are a lot of variables, and we need to be flexible in how we look at this, he stated.

When we are in a recession, we need to do more conservation, Weiss said. It saves money on the power bill, and it gives BPA more kilowatts to sell, he stated. We need to consider it like we do the renewables program – it generates money, Weiss said.

Litchfield took issue with that comment. The Council levelizes the costs of conservation over a number of years, but there are "big upfront dollars" in the early years, he explained. The cost in the first year is way higher than the market, Litchfield said. In the front end, "it's not a moneymaker," he stated.

I'd like to restate our position that conservation and renewables should continue to be linked in any future rate credit, Annick Chalier (PPC) stated.

Eckman pointed out that the program costs BPA laid out for 2005-2006 don't match up well with the 2007-2009 proposal in terms of results. You've got a budget of $80 million annually for expense and $34 million for capital to achieve 40 aMW, he said. In the next rate period, you're looking for 56 aMW for $80 million and $32 million, Eckman said. That indicates you'll have to be much more efficient to reach the target, he stated.

P.M. Agenda: Renewables

Deb Malin (BPA) described the nearly 30-year history of BPA's renewable program, from the 1977 solar-monitoring network to the 2002 power purchase agreement for the Klondike project. In 1996, BPA committed to spend $15 million annually to acquire renewable resources, she said, listing several power purchase agreements for wind, solar and geothermal projects. Malin also noted that the nonprofit Bonneville Environmental Foundation (BEF) was formed in 1997. Four elements from BPA's "balanced scorecard" are applicable to the renewables program, she said, including PF S3, which refers specifically to facilitating the development of regional renewable resources.

The renewables program costs are included in BPA's revenue requirement, Malin explained. At $56 million annually including Fourmile Hill, renewables make up less than 2 percent of the total PBL budget, Malin said.

She noted a three-point BPA financial disclosure statement, indicating that much of the information in the handout is for discussion purposes only, before moving on to specific resource portfolio and budget information.

BPA's existing renewables portfolio totals 198 MW (nameplate capacity), with another 49.9 MW in limbo with the Fourmile Hill geothermal project in California, Malin explained. The energy from the renewable projects is sold separately from "the attributes," which include things like the "green" and "environmentally preferred" designations, she said.

We are in binding arbitration on Fourmile Hill because Calpine failed to file a required geothermal reservoir report on time, Malin reported. BPA is having internal discussions about the future of the Fourmile contract should the arbitration be decided in the agency's favor, she said. The arbitration is set to be complete by October, and the effect on rates may not be known before BPA develops its rate proposal, Malin acknowledged. If the project goes forward now, it could be at least 2008 before it comes on line, she said.

Malin went over a graph showing the online dates and MW size of the agency's nine renewable projects. No other wind projects are in the pipeline for BPA now, she said.

BPA runs one of the nation's largest wholesale renewable marketing programs and sells to over 40 utilities and three national marketers; sales total nearly $3 million per year in gross revenues, Malin continued. BPA's network wind integration service is used by four utilities, she said. Of the BPA-managed expenses, Malin said BPA purchases nearly one-third of the region's wind and funds some of the most pivotal research. The wind power purchases and program costs are projected to be $23.6 million in FY 2005, which is included in rates, she explained.

Revenues from the sale of energy and green premiums offset these costs, and we expect to net about $84,000 this fiscal year, Malin said. She noted that BPA uses the cost of a gas-fired combined-cycle combustion turbine (CCCT) as a surrogate for the long-run marginal cost (LRMC) of power in calculating the offset. The LRMC currently used is $4.00 gas, generating an offsetting value of $44.50 per MW, Malin said.

With regard to customer-managed expenses, she said, BPA is administering $6 million of renewables spending annually through the C&RD program. BPA has agreed with the region to act as "a backstop" if customers do not invest an average of $6 million annually in renewables over the rate period, according to Malin. We don't expect the backstop to be a topic because the commitment is likely to be met, she added.

How does your renewables program mesh with the Council's power plan? Rob Sirvaitis (PRM) asked. The BPA renewables program was not designed "in lockstep" with the Council's plan, Elliot Mainzer (BPA) responded. We are moving away from acquisition and into a facilitator role with renewables, Mainzer said, reiterating that the BPA program and the Council's plan are not closely tied.

Malin explained BPA's $21 million annual management target for renewables. This is a management target, not what is in rates, she clarified. Basically, we are looking for the cost of the renewable program expenses *minus* the LRMC of an equivalent amount of power (offset by the green premium revenues) to be less than $21 million annually, she said.

The $21 million was a negotiated number, Mainzer said. BPA said it would make a $15 million investment in above-market renewables – in other words, the net cost of everything was not to impact rates more than $15 million, he said. If you add to that the $6 million in backstop for customer investments, it's $21 million, Mainzer explained.

You haven't gotten close to an average of $15 million annually, Weiss pointed out.

Will updating the costs of a CCCT have any real affect if you're not acquiring any renewables? Clark asked. That's right, but "we have not 100 percent shut the door" on acquisition if an opportunity presents itself, Mainzer replied. We'd measure any new acquisition against the updated CCCT cost, he added.

Bill Drummond (WMG&T) questioned whether an agreement on renewables that was made when BPA power was $20 per MW is still valid with power at over $30 per MW.

Malin went over a description of how BPA manages to its $21 million annual target. Sirvaitis suggested BPA reword a statement that refers to "manage up to $21 million/year." The $21 million is a cap, so it should be stated more clearly to indicate that, he said.

Malin went over figures on a table of FY 2006-2009 forecasts, noting the costs with and without Fourmile Hill. We have a lean budget, with the only discretionary spending being $0.5 million, she said. Without the Fourmile Hill contract, you would have more flexibility, Drummond commented. Is the Fourmile contract language available? Watson asked. Manary said she would check on whether it is public record.

Malin moved on to the details of the renewable budget. Sirvaitis asked about the $31 million for Fourmile Hill geothermal power in 2007. If you divide that by the output, it's $70 per MW – that's a big number, he pointed out. Several people asked for clarification on the detailed table, trying to match the numbers with other tables.

You can't accurately refer to "losses or gains" when you're calculating the net cost of the program, since you are comparing the renewable power to a hypothetical CCCT, Lon Peters (PGP) said. Dave Hoff (PSE) asked for an explanation of the figures on line 30, entitled "net cost of renewables program." Those figures mean, for example in 2005 and 2006, where the table says $6.084 million and $6.066 million, "if the forward price for electricity meets $4 gas prices, the PF rate would be $6 million higher as a result of the renewable program," Mainzer explained. So that title doesn't accurately reflect what those figures mean, Hoff commented. Earlier, we had called it "Estimated Above-Market Cost for Renewables," Mainzer said. That's better, Hoff replied.

Malin called attention to footnotes for the detailed table. These are important explanations, she said.

How much could you get for the Fourmile Hill power? Carr asked. If we could sell it into the California market, we might realize some transmission savings and could potentially receive more for the power than we could at Mid-C, Mainzer said. The renewable credits associated with the project are also marketable, and they would potentially be more valuable in California, which has enacted renewable portfolio standard, he indicated.

How will these costs be affecting Slice? Nelson asked. All costs of the renewable program are incorporated into Slice as part of BPA's system costs, Allen Ingram (BPA) responded.

We all came in here wanting to know about ways to cut costs, Nelson said. "Some of us came with steak knives and some of us came with chainsaws," he added. But from what I've seen in this budget, "there's not much here to go after," Nelson said.

Malin went over the details of the renewable program support costs, including tasks like solar data collection, wind monitoring and anemometer maintenance. Could you tell us more about wind integration, Pete Peterson (PGE) asked. We said we'd integrate up to 450 MW of wind into the hydro system, Mainzer responded. We did research on how to do this, and we're putting together a contract for a pilot wind-forecasting project, he said. We are trying to keep the costs of integrating wind as low as possible, Mainzer added, noting that BPA has to date sold 10 MW of a wind-integration product.

Malin pointed out that the Maiden wind project remains in the budget because there is a potential $250,000 liability associated with the contract. We don't believe we will have to make that payment, she stated.

With regard to budget cuts during the rate period, Malin said $2 million was cut from renewables support programs to lower rates from FY 2004-2006. There were also large cuts to the acquisition budget, said, citing cuts of a 1,000 MW RFP and site-banking costs in 2002 and a 25 MW acquisition in the 2006 budget.

Recapping other changes, Malin noted that the online date for the Fourmile Hill project was moved out to FY 2007 and may be moved out even further. A BEF memorandum of agreement (MOA) provides for a base payment of $86,000 a year to the foundation ("a true-up" for 2003 contract modifications that were to BPA's benefit but harmed BEF) and directs 36 percent of green premiums to BEF for reinvestment in renewables, she explained. BEF has the advantage of being able to accept and leverage private funds for renewable development, which BPA cannot, Malin said. Was there a public process on the MOA? Early asked. No, Malin replied.

Uncertainties for renewables include risks that may increase the budget, such as the outcome with Fourmile Hill, she continued. The costs of the geothermal project include transmission, Malin said. If the project is delayed or goes away, it could cause the program budget to go down, she said. If we have new options as a result of the arbitration, we'll decide about spending the funds later, Malin indicated.

If you can't get a contract for the Fourmile Hill transmission through the PAC transformer, who is liable? Drummond asked. We'll get back to you on that, staff said.

Another uncertainty for renewables is system allocation – we don't know what load we'll serve, Malin said. The upcoming conservation ROD will determine if the rate incentives for conservation and renewables will be separate or combined, she pointed out. Either way, the $6 million for customers' renewable investment will remain in rates, Malin added.

The customers value the flexibility of having the C&R discount linked in rates, Chalier stated.

Are there other renewable proposals beyond this paper? Schwartz asked. For instance, the Council recommended an evaluation of wind potential, he said. This is our entire budget – we can't study more projects unless we are looking to acquire, Malin responded.

A participant suggested that all of the risks being presented as part of this and other workshop presentations be rolled into the last PFR workshop on risk mitigation.

The meeting adjourned at 3:30 p.m.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on a ongoing basis. The Web address is www.bpa.gov/power/review.

Conservation Program:

1. BPA's Record of Decision (ROD) for the Regional Dialogue issued last week contains principles BPA will pursue in its conservation program. Among the principles, "BPA will use the Council's plan to identify the regional cost-effective conservation targets upon which the agency's share (approximately 40 percent) of cost-effective conservation is based. Please provide the math on this principle, with the assumed IOU and DSI service levels.
2. What is the process for determining the appropriate level of funding referred to in BPA's principles.
3. Provide more information on the accomplishments of the conservation programs (i.e. number of ConAug utilities and aMW savings achieved).
4. Provide the math behind the C&RD breakdown ($30 million conservation, $6 million renewables) on the program expense table.
5. The conservation program capital budget is projected to be $32 million annually for the 2007-2009 rate period. Provide a table that would display the total conservation program, expense and capital, together.

Renewables Program:

1. Is the Fourmile contract language available?
2. The costs of the Fourmile Hill geothermal project are highly dependent on transmission. If you can't get a transmission contract, who is liable?

PFR-004
MAR 10 2005

Bonneville Power Administration
PFR Management Level Discussion
Topics: Transmission Acquisition, Conservation, and Renewables

February 23, 2005
Room 122, BPA Headquarters, Portland, Oregon
Approximate Attendance: 40

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

Opening Remarks

Paul Norman (BPA) welcomed managers to the Power Function Review (PFR). We want to go over the nine categories of BPA's costs generally so we are all grounded for the discussion, and today we'll talk specifically about three of the categories, he said.

BPA had a large rate increase in 2002, and rates have not gone down, Norman acknowledged. Customers are interested in seeing rates go down, and others are interested because our rates fund a lot of activities in the region, he said. "The stakes are high," and we want to provide ample opportunity for you to make input into the costs that go into our rates, Norman stated.

The PFR is taking place outside the formal rate case, he said. This is an opportunity to talk about costs and reach agreement, to the extent possible, about the levels – cost levels will not be part of the rate case, Norman explained. This process is very important to BPA because "once we set the cost levels, we intend to manage to them," he said.

Norman pointed out that the PFR is organized in three layers: technical meetings, management-level discussions, and regional public meetings. We've set up the meetings so the technical sessions occur ahead of the management discussions to give your staff an opportunity to provide you with background on the topics, he noted.

Briefing on PFR and Opening Workshop

We have heard that people find it hard to comment intelligently about costs when they don't know anything about where rates are going, Norman continued. We have a handout today that attempts to give you a simple picture of rates and where they might be headed under various assumptions, he said, adding that the numbers in the packet are to give context. This is where we are starting from "before we get good input from the PFR process," Norman added.

"This is the first time this information has seen the light of day," he said of a handout entitled "2007-2009 Power Costs, Credits, Risk: Overview." His explanation began with a formula of the rate calculation in its simplest form: Costs minus credits plus risk, divided by loads, equal BPA's rates.

As a point of reference, BPA's average 2002-2006 PF rate is 31.5 mills per kWh, Norman said. The revenue recovered through that rate is expected "to fall somewhat short of covering actual net expenses," he pointed out. Over the five-year period, we estimate we will fall about $250 million short and will use reserves to cover costs, Norman reported. He went over a list of major changes in costs and revenues from the current to the upcoming rate period, including expiration of the augmentation purchases, changes to the IOU residential exchange and DSI service, higher PF loads, higher O&M costs, higher debt service costs, expiration of long-term surplus sales, and an assumption that 2007-2009 will yield average water.

In summary, average costs to PF load, without risk mitigation, are forecast to fall from 31.5 mills per kWh in 2002-2006 to 28 mills in 2007-2009, Norman stated. "Setting risk aside," there is a 3.5 mill per kWh drop, he said. "But risk is a big issue," Norman stated. We will have lower reserve levels and much higher volatility in secondary revenues, he said. There is a range of approaches to risk, and depending on the approach, it could more than offset the average cost decrease, Norman said. Risk will be "a huge focus of the PFR and the rate case," he stated.

With regard to costs, credits, and loads, total annual costs are expected to be $230 million per year lower in 2007-2009; annual credits and non-PF revenues are expected to be $435 million per year lower in 2007-2009; and the total PF load is expected to be 1,500 aMW higher, Norman said. Changes in the price for secondary generation and the market forecast for IOU benefits could significantly increase or decrease the 28-mill projection, he added.

We have to deal with risk mitigation because setting rates just to cover expected costs minus revenues leaves the Treasury payment probability (TPP) too low, Norman continued. He recounted how risk has been addressed in the past and noted that in the current rate period, there were cost-adjustment recovery clauses (CRACs). In the next rate period, there are multiple factors driving risk, including low reserves, bringing the TPP target up from 80 percent to 92 percent, the lack of a fish cost contingency fund, high reliance on volatile secondary revenues, and an increase in power liquidity reserves (working capital), Norman explained. This is "our best shot" at what could happen – we see declining average costs, but a more serious risk mitigation problem, he summed up.

There were several questions about figures on the handout, which Norman clarified. Are you expecting to have CRACs? Steve Eldrige (Umatilla Electric) asked. "It's a huge question," and we don't have a position on it right now, Norman replied. The more fixed the rate, the higher it has to be in order to mitigate risk, he added.

Steve Marshall (Snohomish PUD) said he would like to see the IOU benefit issue left open to discussion, perhaps with a ceiling put on the costs. Where do we see the lost revenues due to fish operations? Fred Rettenmund asked. They show up in the lower secondary revenues and the higher purchase costs, Norman responded. We've heard that the Corps has about $300 million in study costs that are going to go into rates at some point, Jim Litchfield (LCG, Inc.) said. Where do they show up? he asked. We've made the conservative assumption that all of those dollars will become plant-in-service and go into rates during the next rate period, Norman replied.

Does the 28 mills include any planned net revenues for risk? asked Geoff Carr (NRU). No it includes none, Norman said. He suggested people continue to review the handout, discuss it with their staffs, and come back with questions and comments.

There is an expectation rates will go down, but with risk factored in, they may not, Norman stated. This is a major opportunity to look hard at every line of costs and ask whether every line item is as low as possible, consistent with BPA meeting its obligations, he said.

Opening Workshop

Norman reviewed the handout from the PFR opening workshop, highlighting the desired outcomes and the list of nine categories of BPA costs. He went over the list of decisions that will be made in the rate case, not the PFR, and the breakout that compares expenses (actuals and projected) from the 1997-2001, 2002-2006, and 2007-2009 rate periods. Norman noted that page 22 is the start of several pages that explain each cost category, with what is expected to change, the risks, and opportunities for reductions. We want to give you the level of understanding that you want about our costs and get your input about what is the lowest level of cost possible in each category, consistent with meeting BPA's objectives, he said.

Norman related a number of "process concerns" he has heard, adding that he has also received positive comments about the process and information that has been provided. People have said they can't comment intelligently on costs unless they know where we're going with the rate, and we've addressed that this morning, he indicated. We've also heard people say BPA needs a management target, with a cap on how high rates can be, Norman said. We're talking about that and would welcome your input, he added. We have also heard frustration about the number of processes and forums, and people have suggested at the end of the PFR, we sum things up in a proposal and take comment on it, Norman said. We're thinking that seems reasonable, but it will take more time – we're thinking about it, he said. And we've also heard the suggestion that we not nail costs down, that we leave them open so if things change, they can be adjusted, Norman said. We would use costs as a risk-management tool, he elaborated.

Norman asked people around the table to comment and relate their concerns. Along with many compliments on the process and quality of information, these are the highlights:

Randy Gregg (Benton PUD): We're concerned about the direction things are going – 31 or 32 mills is high, and we need to roll up our sleeves and work on getting the costs down. We should set a target about where we need to go.

Paul Davies (Central Lincoln PUD): The figure you've put out is higher than we would like to see. We are a pre-subscription customer and will already be going from 21 to 32 mills. I'd say be flexible about your costs – anything over 32 mills would be hard to take.

Jason Eisdorfer (Citizens Utility Board): I understand the frustration about the multiple forums, but the fact BPA is opening things up to let people look at the costs is a rare opportunity, and we ought to make the best of it. In getting to the lowest possible cost, we need to look at programs on a sustainable basis, and we need to think beyond 2007-2009.

Michael Early (Columbia Falls Aluminum): There is an expectation among customers that rates need to go down. You need to have a target so we know where we are trying to go. I'm concerned about not getting to the risk issue until April 18, which is late in the process. It is a big issue, and we may need to get to something that we haven't done before to solve it. If we need to do something different, let's do it.

Kevin Owens (Columbia River PUD): If I were doing this, I'd work with managers in the utility to get at a rate target. It would be a healthier process and the dialogue more meaningful if we heard that BPA has to live within its means. Leaving this open-ended makes me nervous.

Frank Lambe (Emerald): If we don't have a rate decrease at the end of this, it is unacceptable.

Doug Smith (Grays Harbor PUD): I like the idea of a straw proposal at the end of the PFR. We are looking at a total package – leave as much cost on the table for discussion as possible.

Fred Rettenmund (Inland Power): I hope BPA will help us see where the discretionary costs are; pull these out more so we can see the choices and where we can affect costs. When we look at a program, we need to see the debt costs so we have the whole picture.

Scott Brattebo (PacifiCorp): I'd like to see an exercise where we ask, what would the agency look like if we cut $200 million or $300 million? It may be productive to have staff consider if they had to make cuts, what would their department look like. Focus the discussion on areas where change can occur.

Rick Knori (Lower Valley): Set a target and then go back through all of the numbers. It may be that you need to look at changing your depreciation schedule for some things.

Wyla Wood (Mason 3): I take you at your word that you will be listening. As utilities, we are learning to live within our means – good things have been cut. You need to do the same thing.

Paul Elias (McMinnville): I'm alarmed about the possibility of sustaining current rates without a decrease. Your augmentation costs will go down by $640 million. I need to understand why, without those augmentation costs, you could still be at the same level. My commitment is to work hard to understand that.

Nancy Hirsh (NWEC): When you lay out the straw proposal, it would be interesting if you have some "what ifs" – if this piece changed, what would it mean? I want to see what's changeable and flexible. I'm surprised about how much cost is fixed. Keep in mind the legal obligation BPA has for things other than power – it's an issue for BPA in other parts of the country. The more reckless we are here at driving down costs, the more vulnerable we could be nationally.

John Saven (NRU): It's a good exercise for BPA to advance a proposal before the costs are set. I'd also suggest we make this visible to the entire public – some may be oblivious to what the costs are, so I'd suggest you get this information out to the public. It's essential to have a target with the risk included in it. We also want to know what BPA's mandatory costs are versus those over which the agency has control. The information helps us to think about our future relationship with BPA.

Joe Nadal (PNGC): We would like to see a strawman and a target for rates. It would be helpful to know what BPA thinks are the main tradeoffs and where the flexibilities are – bring those forward and highlight them. We would like your analysis of risk earlier in the process so we could see the dollar impact and whether there is wiggle room. The CGS, Corps. and Bureau costs jump out from the budget because of the increase –we'd like to drill down into those costs and maybe get representatives from those agencies here to explain the increases.

Kevin O'Meara (PPC): Since you will be relieved of the burden of the costs related to augmentation and the power crisis, it's incomprehensible how BPA could suggest there could be a rate increase. This will not be a successful process if there is not a rate decrease.

Jorge Carrasco (Seattle): The idea of setting a target rate is desirable – I like the idea of knowing the tradeoffs. It isn't clear what tradeoffs could be made by managers to get to lower numbers, and I would like to see those. I also like the idea of seeing a strawman at the end of the process. It looks like some costs are just handed to you – does BPA have discretion over those costs? A lot of the costs go beyond BPA, and I'd like to know what discretion you have. Risk is a big issue – we have to deal with uncertainty and figure out how we can hedge against it.

Steve Marshall (Snohomish): There is an expectation costs will go back down, and it will be alarming if they don't. The point of this process should be to get to long-term take-or-pay contract commitments. The question is whether we could enter long-term contracts without the proper cost controls in place – we can't just write a blank check. We need to look at specific departments and set the targets. It isn't easy to cut costs, but we can help you to do that if you need help. The only way to prevent the threat posed in the President's budget is through long-term contracts, and we need to focus on how we can get there.

Steve Eldrige (Umatilla Electric): There are some framework issues I hope we address: what would BPA have to look like for us to have a 20-year contact? You referred to making costs as low as they can be while still accomplishing your objectives. Who sets those objectives? You also refer to being below market – BPA's rates should be compared to the cost of generation, not to the market. It may be that a three-year rate term may be too risky, and I hope we vet that.

Ralph Williams (United Electric): With regard to cost cutting, we need to ask, is there a better way to do business that will end up with lower rates? Last time BPA set rates, we were facing deregulation and decisions were made on that basis. I'd challenge senior management to see if synergies could be gained by bringing the power and transmission sides of the agency back together. Can we make the rate simpler? I'd admonish us as we look at a rate going forward, can we make it simpler?

Tom Karier (NPCC): We are starting with a price of about 31.5 mills, and the cost decreases due to the energy crisis, drop us about 7 mills. It looks like half of that comes back in other expenses, without incorporating risk or pressures from new fish and wildlife costs, such as those associated with the Biological Opinion (BiOp). I'd like to see BPA build in institutional efficiency. Set clear performance goals that are widely accepted – these have eluded BPA. Once you have these goals, you can decide on the costs. You also need to consider accountability.

Jim Kempton (NPCC): I'm concerned about where we go with F&W spending relative to the subbasin plans and the BiOp. The Council is looking at those costs and trying to come up with a way to evaluate and perhaps eliminate programs that have served their usefulness. The PFR will help to define those costs.

Norman recounted the key points and offered some responses. With regard to the rate decrease, "we will try to accomplish that," he said. We haven't made the call on offering a written proposal at the end of the PFR, but it seems reasonable, Norman added. We're trying to get to performance goals and accountability in all parts of the budget – it's hard to do in some areas, but I agree we need to, he stated. With regard to the costs from other agencies, we work with them on their budgets, and representatives will be here to talk to you, Norman said. "I totally agree" we should simplify our rate structure and that there is a relationship between our costs and long-term contracts, he said. We are actively pursuing regaining the synergy between the power and transmission businesses, Norman summed up.

Transmission Acquisition Program

Margaret Pedersen (BPA) gave an overview of PBL's transmission acquisition program, which involves purchasing services from TBL and third-party providers. The $189 million annual cost of the program is associated with transmission to deliver energy from resources to markets and loads, generation integration costs associated with Corps and Reclamation transmission facilities, and metering and communication requirements, she explained. The primary goals of the program are to determine and acquire the least-cost mixture of long-term and short-term transmission products that can meet the needs of PBL's secondary energy marketing strategy and to meet the agency's transfer service obligation, she said.

Pedersen described the five components of the program and showed a bar graph of relative costs associated with each: transmission and ancillary services, transfer service, third-party transmission and ancillary services, reserves and other services, and telemetering/equipment replacement. She noted there is a $33 million increase in program costs from 2004 and the projections for 2007. Most of that increase is related to transmission purchases from TBL, which has instituted a 13 percent rate increase, and some is associated with transfer service and load growth, Pedersen explained.

With regard to where there may be opportunities to reduce costs, Pedersen pointed out that the largest component, transmission and ancillary services, varies depending on secondary sales and is managed for least cost. There is not a lot of room to bring costs down with transfer services, third-party services are fixed, the cost of reserves is set by TBL, and there is about $1 million in "wiggle room" in telemetering/equipment replacement, she said. The purchases are managed closely – I don't see a lot of room to reduce the cost forecast, Pedersen summed up.

Management is key, Norman agreed. I don't see a lot of policy calls that could change the costs, he said. The transfer service is a policy call – we absorb those costs in power rates, he said.

Another policy call is to purchase long or short term, Early said. How often does it happen that you have more long-term product than you need? he asked. We look at this on an annual basis, Pedersen responded. We sometimes hold transmission for short-term sales, she said. We have not remarketed short term, but we are looking at that, Pedersen stated. The other side of that risk is buying too little long term, Litchfield commented.

Marshall noted that if PBL can help TBL manage its costs, it helps reduce the agency's overall risk since it shores up reserves. We have an incentive to help TBL keep costs low, Norman replied. He also noted that the TPP would be calculated based on PBL reserves only, not the total agency reserves.

What is the thinking on reintegrating the two parts of BPA? Karier asked. We expect to keep the functional split in rates, Norman said, but we are looking at eliminating costs in duplicate functions. We expect to realize savings in this rate period, and before the PFR is over, you'll see reductions in internal costs as a result, he added.

I expect you may have comments, but I don't know how fertile this ground – transmission acquisition – is for cost cuts, Norman wrapped up.

Conservation Program

Conservation is an example of a topic where there are multiple decision forums, Norman acknowledged. The conservation staff has been working on what BPA's conservation program will look like post 2006, and we've had a work group on that, he explained. "We've had a two-ring circus going," but the budget decisions will be made in the PFR, informed by what's going on in the work group, Norman stated.

John Pyrch (BPA) went through a handout describing BPA's conservation program, including the principles that are guiding the work group in developing the post 2006 conservation program. BPA is on schedule to meet a 220 aMW target during the 2001-2006 period, with 40 aMW planned for 2005, he said. That leaves 22 aMW to attain in 2006 to meet the target, according to Pyrch.

BPA is basing its conservation target during the next rate period on the Northwest Power and Conservation Council's power plan, he explained. BPA's share is 40 percent of the total 700 aMW, which breaks down to 56 aMW per year, Pyrch said. Marshall asked the basis of BPA's conclusion that its share is 40 percent, and Pyrch responded that the figure is based on the 2003 White Book information about firm loads. The figure may need to be updated, he added.

Pyrch explained a graph of BPA's annual delivered conservation savings and targets. Conservation fell sharply from 1997 to 2000, when BPA stepped out of the conservation business, he noted. The amount delivered began increasing in 2001, when BPA began ramping up again, Pyrch said. If we hit 40 aMW in 2005, we will need 22 aMW in 2006, but with the new Council targets, I'm concerned about having a dip – "conservation isn't something you just stop and start," he explained. You lose the infrastructure, and it's hard to recapture it, so we'll likely set a target next year of 40 aMW, Pyrch said.

Conservation didn't stop in 1997, Eldrige said. People continued to buy more efficient appliances and other things – the baseline is never zero, he said. This graph gives the impression that because BPA was not spending, nothing was happening, and that's not true, Eldrige said.

This graph just shows the decline BPA experienced, Pyrch said. But the region went the same way, Ralph Cavanagh (NRDC) stated. Over the three years, 1998-2000, there was a dip, Tom Eckman (NPCC staff) agreed. We do a survey of the region every two years, and the region as a whole tracked with BPA, he said.

Did you count what utilities are achieving outside of the BPA funding? Marshall asked. No, that's not in here, Pyrch responded. So isn't the 56 aMW overstating BPA's share? Marshall asked. If individual utilities are doing more than is reflected here, shouldn't BPA get credit? he asked. BPA would meet its goal faster if it were counted, Marshall pointed out.

We are in the process of trying to track that conservation, Mike Weedall (BPA) said. We agree with your point, Norman added.

Do you have a projection of what you would achieve if you continue along with your current program? Saven asked. We can put that together, Pyrch responded.

If your goal is to achieve all cost-effective conservation, 22 aMW isn't it, right? Cavanagh asked. That's true, Pyrch answered. And BPA didn't have a quarrel with the Council's target, did it? Cavanagh asked. We have been part of the vetting process, Weedall agreed.

What is there for the PFR to discuss here? Bill Drummond (WMG&T) asked. We have a target "set in stone" by the Regional Dialogue, so what is still up for discussion? he asked. This is the decision forum for the costs – we have 40 percent of the Council's conservation target, but how we achieve it and the amount of money that should be in rates is still up for decision, Norman responded.

I commend BPA for setting a target and designing a program to get there, Karier said. The Council has voluminous information about why it came up with the target it did, he added.

Early noted there is a statement in the handout that indicates the target could be adjusted for "naturally occurring" conservation. Our staff is working with the Council on that now, Pyrch replied. What if the Council overestimates the naturally occurring conservation? Hirsh asked. Could there be a move upward for the program? she asked. We assume if the Council makes changes, we can change our targets, Pyrch responded.

At one end of the spectrum is BPA's obligation to achieve 56 aMW and BPA puts together a program to get there – the other end of the spectrum is for utilities to say they will do the conservation, Litchfield commented. The question is, where is the appropriate split between BPA and the utilities, he said.

If the utilities came forward with a credible plan to acquire all 56 aMW, would you drop your program to zero? Gregg asked. Our goal is to ensure that it's achieved, Norman said.

We have been through that scenario, Hirsh pointed out. I'd be very concerned if BPA backs off the 56 aMW – we've been down that path, and it didn't work, she cautioned.

There is a way to do this using the C&RD credits – make them tradable, Karier suggested.

The BPA program would accomplish more if we didn't have to worry about being decremented, Marshall said. That's an unintended consequence of doing conservation – if you cut back, then you lose, he said.

The decrement is a big issue with us, Smith agreed. If we do conservation, we may want to offset a more expensive resource than our BPA purchase, he said. It's a disincentive to do conservation with BPA funds, Smith stated.

We are concerned about the disincentive with the decrement, Hirsh agreed. We will address that issue, Pyrch said.

He continued through the conservation handout, providing a historical perspective on BPA's program, components of the cost, and the list of challenges and risks. With regard to BPA being a "backstop" if utilities fail to deliver the conservation target, Eldrige said he did not support "wiring in" the backstop, which would likely be a rate increase.

We are concerned about a failure to acquire conservation, Hirsh said. BPA has budgeted at the low end of what it has cost in the past for acquisition, she pointed out. We would argue that BPA should live up to its commitment to get all cost-effective conservation – if BPA doesn't meet the target, "we're leaving things on the table," she stated. I thought this group was interested in keeping costs down, Steve Weiss (NWEC) said. This is the cheapest resource around, and we should make sure we get it all, he said. I don't think we should agree to a rate increase to achieve the conservation target, Eldrige reiterated. We are trying to work on an allocation that would get BPA out of fossil fuels completely, O'Meara said. We are developing a mechanism to do that, he added.

Some of the backstop language may have come from a joint customer proposal, Litchfield said. It doesn't mean there would be an automatic rate increase, he said. The idea is, if utilities go out and get conservation, they get the C&RD credit; but if they don't, BPA keeps the credit and uses it for conservation purposes, Litchfield explained.

We are pessimistic about the amount of budget allocated to achieve the conservation target, Karier said.

Let's keep the $80 million in perspective, Carrasco advised. It is a very small percentage of BPA's total budget. I assume the programs BPA funds are working well – they are at Seattle City Light, he said.

Saven said he had signed on to a letter to BPA regarding the conservation target. I think the target is reasonable, but if we can't achieve it for some reason, let's revisit the issue, he recommended. I would like to reserve the right to revisit it – the solution may depend on what the rate is, Saven indicated.

The rate shouldn't be thought of in terms of just dollars – it's also the value of what you are getting, Eisdorfer said. A rate that includes conservation programs has value, he said.

Smith raised the issue of cost-effectiveness and whether BPA's program is eliminating things that are cost-effective. Our definition of cost-effective is what is in the Council's plan, Pyrch said, noting that the Council plan provides a list of measures that are cost-effective. Weedall said the work group was looking at packages of measures as another possible way to get at cost-effectiveness.

Local control is a big issue in getting participation, Marshall said. It's not just about money, it's about the visibility of the programs in the community, he said. The C&RD program is good, and "any changes that would centralize the program are unwelcome," Marshall stated. We hear that – one of our five principles goes to what you suggest, Weedall replied.

Hirsh raised the question of whether the IOU conservation programs would be factored into the target. Norman restated the issue: if the IOUs receive about $10 million through the C&RD, should their conservation be counted toward BPA's goal, or, if not, does that leave BPA with only $70 million of the $80 million budget to achieve 56 aMW. Why would BPA even consider a change like this? Lynn Williams (PGE) asked. It's a mystery to me why you would give the C&RD to the IOUs, but not count the MWs of conservation, she stated.

If money is being spent in the IOU service territory, then it seems you should count the MWs, Ralph Williams said.

The Council did not say how to divide the conservation target among utilities, Karier pointed out. If you include the IOUs, BPA's share would go to 45 percent, he said.

Litchfield pointed out that if BPA collects the $80 million conservation budget as a revenue requirement, everyone will pay and will want something back. If you use the C&RD, there's a different sense about the equity of it – you need to pick a path and things will fall into place, he advised.

In terms of how you establish the credit, I'd like to see things continue to be based on the value to the system, Smith said. Why pay costs in excess of value to the system? he asked.

Pyrch concluded his presentation by reviewing the recommendations and program structure suggested by the conservation work group. He noted that over 65 people were involved in that process. Pyrch indicated that BPA is using this as the foundation for its post 2006 conservation program proposal.

We are looking for ways to achieve the conservation goal and for opportunities to achieve the goal at lower costs, Norman said. He recapped the comments and suggestions, including: take credit against the 56 aMW with what the publics are achieving "on their own nickel"; look at naturally occurring conservation, but be wary of overestimating; consider the decrement issue – a decrement can discourage utility spending on conservation, no decrement can encourage utility spending; and allow trading credits in the C&RD program. I heard risks issues, including the adequacy of the proposed budget to capture 56 aMW annually; loss of utility participation if the program is constrained;

IOU participation in the discount being handled differently; and BPA providing a backstop for utility spending.

I thought you committed to the Council's target, which is effective now, yet you don't start the effort until 2007, Weiss commented. BPA is already going to be behind in achieving the goal, and "you ought to catch up," he advised. The value of the conservation revenue is not captured explicitly, Weiss said. If you calculate the benefit and display it, you may find conservation already pays for itself, he said. You should calculate the value of the conservation against the costs, Weiss recommended.

I would like to see what the current program would yield, Saven reiterated. Karier said big questions are whether to adjust the target to include the IOUs and what BPA can achieve with the programs it proposes. He said sticking with the standard of basing the discount on the value of a measure to the system is the better way to go.

What has been the cost of a MW of conservation over time? Lynn Williams asked. Grist said the figure varies between $1.5 million to $2.2 million per MW, depending on the year – "it's been very lumpy over the last 10 years." BPA is proposing to spend a lot less than that per MW – the target is up 40 percent, and the budget is flat, he pointed out.

Carrasco said any implication that BPA ought not to be spending on conservation goes against the success of the programs. These programs are effective, he said. In terms of the conservation program, Carrasco recommended BPA think about whether changes proposed to the C&RD makes sense, err on the side of providing flexibility for local control, and consider whether $80 million is the appropriate funding level. He cited several positive accomplishments of the C&RD program, noting that only one utility chose not to participate. There might be concerns about the money, but the results are worth it, Carrasco stated.

Your summary emphasized cost control, but there were comments on the other side too, Hirsh told Norman. I'd like you to go away giving equal emphasis to that side, she said. Our philosophy on this is to stick to the target and then see what is the lowest-cost way to meet it, Norman responded. There are three steps here, Karier added: set performance standards, achieve them cost effectively, and provide accountability.

Renewables Program

Elliot Mainzer (BPA) said he had two aims with his presentation on BPA's renewables program: I want you to understand how we manage renewables and to go through what we've forecast for the 2007-2009 period. After noting the financial disclosure statement, he laid out the history of BPA's renewable program, listing the acquisitions made from 1977 to the present, and he went through the strategic objectives and where the $56 million program fits within the power expense structure.

BPA is not in the acquisition mode, but is taking on a facilitation role with renewables, which includes offering wind integration services, he said. BPA purchases 198 MW of wind power and funds valuable research, Mainzer said, adding that wind purchases and program costs total $23.6 million per year. Revenues from the sale of the energy plus green premiums offset the costs, and the program is expected to have a net gain of $84,000 in 2005, he reported.

Mainzer outlined the $21 million per year management target for the program, explaining how BPA calculates program costs and noting the total includes $6 million for renewables that utilities pursue through the C&RD. Mainzer pointed out that the program values renewable energy against the long-run marginal cost of power from a gas-fired combined cycle combustion turbine, with gas prices at $4 per MMBtu. He also went over the details of the renewable budget, beginning with 2001 and projecting through 2009.

Costs of the 49 MW Fourmile Hill geothermal plant are a big variable in the budget, Mainzer said. BPA is in arbitration with Calpine, the developer, because the company failed to meet a deadline for proving out the steam, he explained. The arbitration will clarify BPA's rights with regard to the future of the project – for now, BPA is assuming the costs will go into rates in 2007, he clarified.

Mainzer went over additional details in the budget, explaining the relationship and funding arrangements between BPA and the Bonneville Environmental Foundation (BEF). An MOA signed with BEF makes our relationship more businesslike, he said. In summing up the information on the table, Mainzer said the net cost of BPA's renewables acquisitions is negligibly above market. Or another way to look at it is, BPA's rates are so far no higher with the renewables program, he said.

There were some questions to clarify the details of the budget, then Mainzer continued through the renewable forecast, details of the BEF MOA, the 2002-2004 cuts in the renewables program, and uncertainties, including the Fourmile Hill arbitration. Is it possible you won't complete Fourmile? Brattebo asked. It's possible, Mainzer answered. Among other uncertainties, Mainzer mentioned the structure of the C&RD program and whether conservation and renewables will be separate or combined, as they are currently.

The big question is Fourmile Hill, Early pointed out. Why have you assumed Calpine will come forward with the full amount in 2007? he asked. Being conservative, Mainzer responded. We hear you suggesting we do a different forecast and take the project out, at least for 2007, Norman commented.

I'd highly recommend we take Fourmile out of the projection for 2007-2009, Saven stated. I can't imagine there is a reason we can't make the decision to do that, he said. At a minimum, we'll try to resolve the online date, Mainzer replied.

I appreciate the line item for renewables support, Hirsh commented.

We have renewables portfolio bills before the legislature in Washington, Marshall pointed out. We should be careful we don't get two competing mandates on renewables, he said. The bills don't define hydro as renewable, Marshall added. If you have any influence, it would be good to see about making input that would keep the bills consistent with the Council's plan, he said.

I'd urge you, if you could, to get the Fourmile question resolved within a few months, Randy Hardy (Hardy Energy Consulting) said. It has implications for other decisions, including transmission, he said.

The main variable this category is cost of Fourmile Hill, Norman wrapped up. We're hearing the suggestion that we could at least slip the date for when the project goes into rates, he said.

We have "a marathon meeting" March 16-17, Norman said in concluding the day.

The meeting adjourned at 3:40 p.m.

Follow-up questions and information requests:
Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on a ongoing basis. The Web address is www.bpa.gov/power/review.

1. In regards to Conservation, do you have a projection of what you would achieve if you continue along with your current program?

PFR-005
MAR 10 2005

Bonneville Power Administration
Power Function Review Technical Workshop
March 1, 2005

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 30

Internal Operations Charged to Power, Depreciation/Amortization, Federal Net Interest, Non-Federal Debt Service, Debt Management

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

Opening Remarks

Michelle Manary (BPA) welcomed participants and said she would soon post the most recent Q&As to the website. At last week's managers meeting, Paul Norman handed out our first cut at a base point for rates, and copies are available with the other handouts today, she said. The calculation does not include risk, which was a key point of his presentation at the meeting, Manary said.

We have heard that people are having a hard time identifying policy issues in our Power Function Review (PFR) presentations and discussions, she went on. On March 15, we'll provide that – the policy issues and the dollar impacts, Manary said. We have also heard that participants would like a draft proposal once the PFR meetings conclude, she stated. We will likely have a draft proposal out the first week of May, and we will be extending the comment period to later in May, Manary said. That means we will be moving the April 20 wrap-up workshop into May, probably the second week – we will let you know the schedule changes as soon as we can, she said.

I. Internal Operations Charged to Power

David Steele (BPA) noted the financial disclosure statement and began a presentation on the internal operations charged to power rates. The internal operations objectives for the PFR are to assure power rates reflect the lowest practical costs to meet BPA's objectives and to discuss opportunities for further cost reductions and actions BPA is currently taking in that regard, he explained. Internal operations charged to power are expected to be about 5 percent of the agency budget or $116 million annually in the 2007-2009 period, Steele said. About half the costs are directly within PBL, and the other half are allocations from corporate, he noted.

The costs in the next rate period are forecast to be about 8 percent higher than they are now, Steele continued. The largest expense is personnel, with 77 percent of the costs related to employee compensation, he said. Another 14 percent is service contracts, and the remaining 9 percent is travel, training, materials and supplies, and other miscellaneous, Steele said. While PBL staff has decreased overall, increases in operational functions are driving the increase, and most is related to efforts to extract more generation from the hydro system through efficiency projects, as well as Slice staffing, he said.

Steele said the efficiency projects are designed to extract more generation from the hydro system, and about 140 MW of additional generation has been gained. The costs include hardware and software and some additional O&M costs at the hydro projects, he explained. Mark Stauffer (NWE) asked how much the 140 MW have cost overall, and staff said they would provide that information.

Steele explained where the internal operations costs show up on the BPA financial statements and what the costs entail. What is the management direction on these costs for the next rate period? Are you aiming to stay at 2001 levels? Kevin Clark (Seattle) asked. Steele said while there was no specific direction about staying at 2001 levels, many projected costs for 2007-2009 are still at 2001 levels.

Steele went over a list of PBL internal operations cost cuts and accomplishments, including the IT reorganization. He noted the average annual cost for fiscal years (FY) 2007-2009, adjusting for the IT reorganization and transfer, is equal to costs in 2001.

"The best thing we've done this rate period is to hold costs down, and getting out forecasts to reflect actual spending. One way we have accomplished is by eliminating contingency budgets", Steele continued. The contingency budgets, which now exist only at the senior vice president level, were for unplanned events not captured in the forecast, he explained. They started at $1 million with the 2003 safety-net cost adjustment recovery clause (SN CRAC) rate case but have since been reduced to $500,000, he said. Since 1994, the gap between our forecast expenses and actuals has narrowed substantially, Steele said, noting that Senior Vice President Paul Norman wants forecasts that reflect the "real" cost of doing business.

With regard to FTE, he pointed out that 2005 numbers rose for Corporate and fell for Power with the transfer of the IT group. The IT transfer also affected contractor numbers from 2004 to 2005, with decreases in Power and increases in Corporate. Other than the IT reorganization, there appears to be reductions in the number of Power contractors, and Lon Peters (PGP) asked what those were. We'll get back to you on that, Steele said.

He moved on to a table of PBL's internal operations costs. There were a number of questions about the expense categories and figures. Joe Hoerner (Tacoma) asked about the "Awards" category and the increases projected for 2007-2009. The increase reflects the chief operating officer's direction with regard to our recognition policy, Steele said. This is our forecast of how to budget for it, he added. Terry Esvelt (BPA) explained that under the previous BPA Administrator, there was an emphasis on performance-based compensation, "with some pay at risk." The program was slashed during the power crisis, but now is ramping back up, he said. We have a three-part program for awards, and awards are based on meeting performance targets, Esvelt said.

Why don't you tell customers about the performance objectives, Clark suggested. He indicated it would help allay "skepticism" that awards are given automatically. It seems you have a program that is better than just automatic, but we don't know about it, he said.

There was a question about the distinction between service contracts and supplemental labor contracts. Kelly Kintz (BPA) said the supplemental labor contracts are largely for clerical and other support staff. The contracts give BPA the flexibility to ramp up and down, depending on staffing needs, he said. The service contracts are for services and expertise that don't necessarily exist on staff, such as auditors or IT, Kintz said.

Clark pointed out the difficulty of trying to track the benefits of the IT reorganization in both personnel numbers and costs. The purpose of the reorganization is to save money, and I'd like to make sure that is happening, he said. Tell us what dollars reflect the transfers from PBL to Corporate, Clark requested.

The drivers that increase internal operations costs are "people related," including pay increases, health insurance, and other benefit increases, Steele said. New industry requirements from customers, constituents, and other stakeholders pose risk for increased costs, he said. Steele listed where opportunities for reductions in cost lay, including the Enterprise Process Improvement Project (EPIP), which is just getting started; several program areas, including IT; and implementation of a voluntary separation incentive (VSI) and voluntary early retirement authority (VERA).

With regard to an agency-wide initiative to reduce the grade structure among the GS-13 through GS-15 positions, Hoerner noted the timing for getting results from the effort does not line up well with the schedule for issuing a draft rate proposal. We will try to get some of the potential reductions into the proposal, Steele said. Will the grade reductions offset the pay increases? Hoerner asked. Steele said he expected that to be the case, but did not know offhand by how much. Steele said 40 percent of the positions in the agency are GS-13 to GS-15, and 72 percent of the positions in PBL are in those grades. Peters asked about the timing of reductions from EPIP. We also hope to have some of the EPIP reductions quantified for the draft rate proposal, Steele indicated.

By the end of the PFR, we will quantify the expected savings from the initiatives we've outlined, and we'll include those in the initial rate proposal, he summed up. We'd like your help in identifying additional areas for cost reductions and efficiencies, Steele said.

How about turning the question around, Scott Brattebo (PacifiCorp) suggested. You tell us what your organization would like if you cut 5 or 10 percent, he said. We could take a cut at that, Steele responded. In seven functional areas, we've been handed target reductions, and we're looking at 10 to 40 percent cuts in those areas, Esvelt added.

Participants took another look at the PBL organization chart. Hoerner noted that a number of positions have "acting" staff. Are these jobs going to be filled permanently? he asked. Steele pointed out that a number of the positions have acting staff because the managers are on leave or on other assignments and will be returning.

Clark said he heard talk of merging the PBL and TBL cost functions into Corporate. I'd like to weigh in against that, he said. We think Corporate has done a poor job of controlling costs, Clark stated.

There were questions about the One BPA and EPIP processes. With regard to One BPA, the thinking is that when we did the separation of PBL and TBL, the standards of conduct might have been stricter than they needed to be and that some efficiencies may be gained by having more integrated functions, Steele explained. EPIP, on the other hand, is looking into individual program areas and taking "a horizontal" cut across the agency to see if there are similar functions being performed in separate places, Esvelt said. Some of the seven EPIP studies integrate with One BPA – there is overlap, he clarified.

How will you involve customers in EPIP? Geoff Carr (NRU) asked. We'll take that as a comment that you want a public process, Steele responded. We'd also like information about One BPA, Doug Brawley (PNGC) said.

<u>Corporate G&A</u>

Esvelt went over the objectives of the PFR with regard to Corporate General and Administrative (G&A) overhead and Shared Services costs charged to power rates. "I am frustrated about not seeing corporate set a good example with cost control," Clark stated. What is the BPA management directive in this area? he asked. It depends on where you are looking, Esvelt responded. Corporate costs are growing at about the rate of inflation, and EPIP will make a dramatic difference, he said. "Show me the math" that demonstrates corporate costs are not growing faster than inflation, Clark replied. The business lines are holding their costs flat, but we don't see that with Corporate, he said.

Esvelt explained the evolving nature of the Corporate function, noting that shifts in the level of service provided, location of a function, and cost allocation between TBL and PBL have caused some confusion. I'd like to see how the costs are moving in the IT consolidation and how they are being charged out to programs, Clark requested.

Esvelt went over the Corporate organizational chart and noted that organizations being reviewed as part of EPIP are designated with stars. Where possible, we will include estimates of cost savings into the draft rate proposal, he said. How about having a session on EPIP? Carr suggested. We'd like to look at how it's going, he added.

Moving to FTE graphs, Esvelt noted changes that have occurred in BPA staffing levels over time. How many people do you expect to leave under the VERA? Hoerner asked. "The challenge is that it is voluntary, so it's impossible to know exactly what will happen," Esvelt responded. The deadline for applying is March 31, he added. The graph on page 23 dives into detail about the FTE breakdown within the Corporate organization, Esvelt said. Most of the increase from 2004 to 2005 is the IT consolidation, with FTE moving from the business lines to Corporate – about 100 people moved from the business lines, he said.

Please document the changes you say are occurring in Corporate, Clark said. You keep saying the FTE are going down, but your graphs show them going up, he said. It's hard to track "when it looks like a shell game" – we have to see detailed charts, Clark stated.

There was a question about the increase in Corporate FTE from 2000 to 2002. That increase was related primarily to TBL ramping up for its infrastructure projects, Esvelt responded. Adding the FTE in TBL meant adding support personnel, IT, and recruiters, he added. Does it take one Corporate staff for every three added in TBL? Peters asked. No, there were other things included, Esvelt said.

The FTE amounts represent a forecast prepared before the EPIP and other efficiency efforts were underway. Decisions on FTE reductions have not been made yet – yesterday you got the EPIP targets, and that's our best guess about the possible savings, Esvelt responded.

"We are bowled over" by the 500 IT staff, given the size of your total work force, Stephany Watson (Krogh and Leonard) stated. Have you done any comparisons of how this measures up with comparable organizations? she asked. By 2006, we have challenged the IT manager to reduce costs by 25 percent, Esvelt responded. We're banking on the VSI and VERA to reduce personnel, he said, acknowledging that the challenge is a dollar reduction and not necessarily a cut in FTE.

Corporate G&A Cost Allocations

Kintz gave an overview of how Corporate G&A costs are allocated to the business lines. He went over the guiding principles for allocation methodologies, including they be equitable and fair, and represent "a causal relationship" to the services provided, and he gave examples of the methodologies. Kintz described the nine cost pools and the percentage split between PBL and TBL. Clark asked for a breakout of Corporate costs that shows the direct charges and the allocated costs. Throw the TBL onto the table, too, so we can roll up the full costs of these organizations, he added.

Annick Chalier (PPC) asked why 40 percent of industry restructuring cost is allocated to PBL. We reviewed for the allocation the types of things being done by that function, Kintz responded. We could reconsider, depending on what happens at the GridWest decision points, he added.

Stauffer asked for a breakout of costs associated with "Corporate Cost Pool." Did you consider a split other than 50-50? he asked. Kintz said the pool covers the governance structure for the agency – one month costs can be weighted to one business line and the next to another. There was a lot of internal debate about the split, he acknowledged.

Stauffer asked how One BPA would affect cost allocation. There will be a review of the cost pools, Kintz responded. We will continue to do something similar to what we're doing now, but we'll have to rethink things and determine which is the benefiting function – we'll try to get a measurement that best reflects the consumption of services, he said. We want to be equitable and fair, Kintz added.

"That's one reason not to get too carried away with One BPA," Clark advised. It is better to have people within the business lines oversee costs rather than having it be entirely a Corporate function, he said.

I'd like to see the numbers associated with each cost pool, Stauffer said. I'd like to know how big each cost pool is and how much of the total it represents, he said.

Clark asked that a table like that on page 31, FY 2001-2009 Corporate Costs, be posted to the website. If you post it in Excel, we could do our own calculations, he said.

Kintz wrapped up with delineating functions that direct charge to one business line or the other when circumstances warrant: legal, Slice audit, risk management "back office," and WNP-3 settlement exchange agreement costs.

Corporate G&A Costs

Bryan Crawford gave an overview of the table on page 31, which details Corporate costs from 2001 to 2009. Clark asked for the amortization and debt service associated with the expense categories. I want to be able to see something that tells me the total cost of a program, he said.

Crawford went through a list of observations about Corporate G&A. The large increase in G&A from 2004-2005 is driven primarily by the IT consolidation, he said. As a direct result of the IT consolidation, the Shared Services budget charged to Corporate G&A also increased, he said. The IT consolidation aside, there was an approximately $7.6 million increase in Corporate G&A due to several factors, including increased GridWest costs, consulting services associated with EPIP, support for financial and risk management, and increases due to cost of living raises for personnel, Crawford explained.

Brattebo asked about the allocation of the Line 22 IT costs on page 31. Should you come up with a new allocation? he asked. "Consolidation is wonderful," but if it doesn't save money, you have to consider, what's the point? Brattebo asked. Are your current IT costs similar to those in the previous organizational structure? Dave Hoff (PSE) asked. There is not enough information to tell yet, Kintz acknowledged. That will be part of our evaluation, he said. Clark asked about the allocation versus direct charge of overhead costs for the new IT organization. Kintz diagrammed and explained how the allocation/direct charge takes place. It seems the actual costs would help you figure out the allocation instead of just doing the general splits, Stauffer commented.

Why is there a jump in IT costs from 2006 to 2009? Clark asked. When we consolidated IT, we held the costs to SN CRAC levels, even though the budget request was actually higher, Crawford explained. The 2007-2009 projections go back to the amount in the budget request, he said, adding that there will be new IT numbers before the draft rate proposal. Why is the overall expense growing? Clark asked. These are old numbers, Kathy House (BPA) responded. We know they are high, and we don't expect to stay at that level, she said. But we had no way to figure out what the out-years would look like, and we're doing that now, House stated. We'll have revised lower numbers for Corporate G&A in April or May, Steele stated.

"I'm shocked" that the numbers from the SN CRAC were not sustainable, Clark stated. What do we tell our bosses for the management meeting? he asked. This will be an area where the numbers are coming down, Manary responded. The schedule for preparing new numbers did not sync with our PFR/rate case calendar, she added.

There were more questions about which costs would come down, and Crawford said cost of living adjustments and inflation are driving up costs in the out-years. The figures don't reflect EPIP or less FTE, he noted. I'd expect you could show cuts in FTE by April, Clark commented. They will be part of EPIP and One BPA, Crawford said.

What is Line 27, Technology Conformation/Innovation? Jim Litchfield (LCG) asked. John Holmstrom (BPA) explained that BPA has not done much in terms of technology development in recent years and the new direction is to propose a technology innovation plan. The plan will be "strategy driven," looking at business needs and developing a road map for applied technology, he said. For example, with security, there are broadband innovations for communication that may be useful, Holmstrom said.

We don't have a specific list of what we will do, it will evolve, but we'll require a business case to justify the use of the funds, he indicated. The proposal is to have competitive projects that identify technologies with potential to improve our business and to test and adapt them to our needs, Holmstrom explained.

Why is the budget $8 million? Clark asked. We are targeting an amount of up to one-half of one percent of our revenues, Holmstrom replied. We used to participate in EPRI at up to 1.5 percent of revenues, he added.

The discussion wrapped up with Manary saying she would set up a smaller meeting for those interested in following up with more questions on Corporate, IT, and Technology Innovations topics.

II. Depreciation/Amortization, Federal Net Interest, and Non-Federal Debt Service

Valerie Lefler (BPA) pointed out the financial disclosure statement and went through the workshop objectives and agenda. She referred participants to a sheet entitled "Potential Opportunities for Change" that identifies which are PFR and which are rate case issues.

Costs associated with depreciation, amortization, federal net interest, and non-federal debt service are driven by prior decisions about capital investments, Lefler said. Linc Wolverton (ICNU) asked when it would be appropriate to address the assumptions about plant-in-service. I think it would be both in the PFR and the rate case, Lefler responded.

The Corps and Reclamation will make presentations in this process, and you could address it with them, Steele added.

It seems there are two steps to making the plant-in-service assumptions, Clark said: look at the projections and at what has happened historically. Look at what the experience has been historically and figure out an appropriate "fudge factor," he said.

Lefler pointed out the graph of BPA's revenue requirement and said costs associated with depreciation, amortization, federal net interest, and non-federal debt service make up 39 percent of the total. Ron Homenick (BPA) went over definitions of these categories of expenses along with graphs showing where the costs for each averaged from FY 1997-2001 to the initial forecast for 2007-2009.

The main driver of the change in FY 2007-2009 depreciation and amortization costs is Corps and Reclamation plant-in-service, and a sizeable portion is the Columbia River Fish Mitigation (CRFM) costs, Homenick said. Other costs have been consistent, and legacy conservation has been declining, he pointed out. We have not forecast appropriated capital other than CRFM, Homenick noted.

Brattebo asked about the CRFM column on the table. We have heard about the $300 million in studies, he said. Is that in here? Brattebo asked. Lefler said it was not and she would find out when it is expected to become plant-in-service and go onto BPA's books. The mitigation analysis is more than just research projects, it includes work on the ground, she clarified. This adds up to $700 million and we still don't have the $300 million mitigation analysis? Carr asked. What's in here? he inquired. It is flip lips, removable spillway weirs, corner collectors, and other things at the dams, Lefler said. This just keeps growing, Carr commented.

What's coming off the books? Hoff asked. Some resources that have been amortized over 15 to 20 years will be dropping off – primarily IT investment, Homenick responded. Hoff asked for a table that shows what is coming off BPA's books.

The primary driver for depreciation and amortization expenses is the level of capital investment, Homenick continued. He went over the program components of the $201 million average annual expense for FY 2007-2009, noting that 52 percent is Corps and Reclamation, 7 percent is PBL, 11 percent is fish and wildlife (F&W), 15 percent is legacy conservation, and 15 percent is ConAug.

There were several questions about how the in-service date is determined for the CRFM. It has been a Corps decision, Lefler responded. Why isn't this a BPA decision? Why doesn't BPA have a role? Clark asked. The Corps follows its own capitalization policies and guidance about when they put things into service, and when they do, we cover the hydro portion, Kintz responded. The treatment of the CRFM mitigation analysis was included in a Congressional Act, Kintz said. Congress went so far as to treat the accounting? Clark asked. Yes, Kintz responded, to the extent the Corps of Engineers is interpreting the legislation regarding the fulfillment of the legislative requirement.

What's the rationale for having ConAug amortized over such a short period, 2002-2011? Litchfield asked. It's to assure cost recovery, Homenick answered. It's part of the customer contract and will be recovered within the contract period, he said. Kintz added that amortization decisions are made based on Financial Accounting Standards Board (FASB) rules and Generally Accepted Accounting Principles (GAAP).

Homenick went over the depreciation/amortization forecast, and staff clarified the basis for amortization schedules of different lengths and the application of FASB 71 to determinations for Corps, Reclamation, and BPA's direct F&W program. A Corps or Reclamation project, like a fish ladder at a dam, that is directly related to a revenue-generating facility is amortized over 75 years, Kintz explained. But based on guidance from the Northwest Power Act, if we fund an intangible asset through our F&W program that exceeds $1 million and has a life span of at least 15 years, it is amortized over 15 years, he said. We developed this policy in the early1980's, Kintz added.

Homenick explained graphs of the amortization/depreciation trends and a comparison of actuals to forecasts in historic periods. The PBL revenue requirement includes a component called Minimum Required Net Revenues (MRNR) to ensure covering annual cash requirements, he said. MRNR, which was forecast for the 2007-2009 period, is calculated as the amount by which BPA's payments to Treasury for amortization and irrigation assistance exceed the total of non-cash expenses and revenues, Homenick said.

The forecast is based on the repayment study, which is used to calculate a schedule for repaying the federal and non-federal debt, he said. What's happening is that the study is reshaping our federal debt service around the non-federal debt structure, Homenick said, adding that BPA has been exchanging non-federal for federal debt with its advance refunding of Energy Northwest (EN) bonds. So the Debt Optimization Program (DOP) is causing this to be so large? Hoff asked. You're exchanging the period in which you pay the debt – the point of advance refunding was to be sure we didn't cause an increase in overall debt service, Homenick responded.

Did you make the payments assumed in the DOP runs? Stauffer asked. The planned principal payments to the Treasury do not change, and we have done what was forecast, Homenick said. Back in 2000-2001, we started the advance refundings, and that rolled the non-federal debt out from 2009-2012, Nadine Coseo (BPA) explained. We agreed that for any EN debt service that was rolled into the 2013-2018 period, we would pay the equivalent in federal debt – the non-federal debt is less in the next rate period, but the federal debt is higher, she said.

What we're seeing is a ramp up in federal principal, Clark commented. Could you give us the projected new refinancing issues that were used to calculate the tables on pages 17, 20, and 23? he requested.

In the base case plan with DOP, each year when the principal payment is due, we refinance non-federal debt and push it to the 2013-2018 period, Don Carbonari (BPA) explained. We pay federal debt for every dollar of non-federal debt that is due, Homenick added. We ran the repayment study with this scenario, and we end up with the cash requirements on the table on page 17, he said. "We have a dollar-for-dollar commitment" to replace the non-federal debt with federal principal payments, Homenick reiterated.

So the net effect is to increase one side, which is offset by the other side – the impact is net zero, Hoff commented. That's a good point – we will put more text with this to explain it better, Homenick said.

Clark suggested that BPA, in developing the power revenue requirement, include the EN debt "below the line." For the agency financial statements, you can continue to report it as an expense on the income statement and show it on the balance sheet with federal debt, but for setting rates you should include it as a cash consideration so customers won't have the concern they may be paying twice, he recommended. That's an excellent point and probably a reasonable way to go, Homenick responded.

Federal Net Interest

Homenick explained the components of federal net interest expense and noted there is a 28 percent increase from 2007-2009. But we haven't forecast the interest income on our cash balance yet, he said. Coseo pointed out that the table assumes when short-term bonds are rolled over, they are rolled to long term at the forecast federal interest rate.

Homenick went over the risks, which include the potential for an increase in interest rates and the affect that would have on the cost of Treasury borrowing, as well as opportunities for reductions in the expense. He noted that before the draft rate case proposal comes out, assumptions would be updated with regard to DOP. Hoff asked about the interest credit included in this forecast, and Homenick said it only assumes BPA is accruing interest on the cash put aside during the year for repayment. It does not include total earnings on the balance in the Bonneville Fund.

Homenick described capital funding mechanisms, and he listed the drivers of change in the next rate period, explaining that DOP increases the repayment amount on federal bonds and appropriations, which reduces interest expense on the federal side. The CRFM plant-in-service schedule is "a wild card" for the future interest expense – whatever we assume seems to change, he noted.

There were clarifying questions about the actual and forecast federal net interest expense, including whether the forecasts included DOP. We haven't forecast any of the DOP actions that are likely to occur from the current year through 2009, Homenick responded. "The big message" with the actuals versus the forecast is that "actuals are a lot lower because debt optimization came along after we filed the last rate case," he clarified.

Non-Federal Debt Service

Carbonari explained the largest piece of the debt expense pie, non-federal debt service. The non-federal debt, which is third-party debt service or payment obligations associated with capitalized contracts and other long-term fixed obligations, is forecast to go up by 26.6 percent in 2007-2009, he said. The largest component in this category is the EN debt, which has never been level, but rather is shaped to minimize the revenue requirement and benefit ratepayers, he said. The predominant drivers of the increase in the non-federal debt category, Carbonari explained, are actions taken from 2000 to 2004, including debt optimization, reserve fund free-ups, refinancings for savings, and "new money" financing at EN.

He went through a list of opportunities to decrease the forecast, noting that the tradeoff for each action is indicated in parentheses. One of the opportunities relates to longer-term financing of fuel for the Columbia Generating Station, and Steele pointed out that EN has a good fuel-purchasing program and is in the top 10 percent of nuclear plants nationally. Carbonari also detailed where debt management decisions are made, pointing out that for EN transactions, the EN board is part of the decision making. He said BPA's and the EN board's position is not to put any EN debt out beyond 2018.

You haven't talked to EN about debt financing capital in the 2007-2009 period? Brawley asked. That's correct, but we could consider it as a recommendation from customers to do so, Lefler responded. If it raises rates, we wouldn't do it, she added.

Carbonari detailed the components of the third-party debt, which in addition to EN includes customers' generating and conservation projects. He pointed out that non-federal debt service is not level year to year. "It's erratic, it's never been level," Carbonari explained, adding that the primary factor that drives the level is the amount of maturing principal in any given year. Have you had discussions about reshaping the third-party debt to lower the debt service? Carr asked. In 2003, we refinanced some debt to get the interest-rate savings, but we did not restructure debt, Carbonari responded.

BPA's debt, federal and non-federal, is managed as a single portfolio, Carbonari continued. It is managed to restore borrowing authority, control or lower costs, and increase liquidity, he said. Debt management refers primarily to three types of activities, according to Carbonari: debt optimization, reserve fund free-ups, and refinancing for savings. He explained what debt optimization entails and reported that advance federal payments made with DOP funds from 2001 to 2004 restored $600 million in BPA borrowing authority. In addition, BPA was able to pay down about $500 million in appropriations that were coming due, Carbonari said.

He explained the hundreds of millions of dollars in reserve fund free-ups that occurred between 2002 and 2004 and acknowledged that the tradeoff is losing interest earnings. The effect of the earlier free-ups for the 2007-2009 rate period are forecast to be a loss of about $49 million in available free-ups plus the interest that would otherwise have been earned, he said.

With regard to refinancing for savings, BPA has refinanced billions of dollars over the years, Carbonari continued. I presume when you do these transactions, you have to hire outside experts, like bond counsel, Watson said. Do you have an analysis that shows the proceeds offset these extra expenses? she asked. Yes, we do that analysis, Carbonari said. If we can't save at least 5 percent, we won't refinance, he said.

In summary, Carbonari said managing BPA's federal and non-federal debt as a single portfolio has had significant benefits. The weighted average interest rate on BPA's outstanding liabilities decreased by a percent from the end of FY 2000 to the end of FY 2003, he said. Debt management actions produced over $100 million in interest savings, he concluded.

Carr asked BPA to provide an example of the refinancing it is considering for 2005. Manary said she would stay after the meeting to discuss how to condense the technical information for the managers' meeting March 16.

The meeting adjourned at 4:10 p.m.

Follow-up questions and information requests:
Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on an ongoing basis. The Web address is www.bpa.gov/power/review.

1. Efficiency projects are designed to extract more generation from the hydro system, and about 140 MW of additional generation has been gained. The costs include hardware and software and some additional O&M costs at the hydro projects, he explained. How much the 140 MW have cost overall?
2. Other than the IT reorganization, there appears to be reductions in the number of Power contractors. Where have those come from?
3. Explain BPA performance objectives around rewards.
4. Provide a list of potential reductions from the initiative to reduce grade structure.
5. What would your organization look like if you cut 5 or 10 percent?
6. How will involve customers in the EPIP process?
7. Provide more information on the one-BPA process.
8. Provide a breakout of corporate costs that shows the direct charges and the allocated costs. Include TBL as well.
9. Provide the numbers associated with the "Corporate Cost Pool."
10. Provide the amortization and debt service associated with the expense categories.
11. There is a ramping up in federal principal. Provide the projected new refinancing issues that were used to calculate on pages 17, 20 and 23.
12. When is the $300 M in studies forecast to hit the books?
13. Please provide an example of the refinancing it is considering for 2005.

Bonneville Power Administration
Power Function Review Technical Workshop
March 10, 2005

PFR - 006
APR 01 2005

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 10

Internal Operations Charged to Power

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

Introduction

Michelle Manary (BPA) said the meeting was a follow-up to last week's session on internal operations, which raised a number of questions that need clarification. We have posted updated material on the website, as well as a backgrounder on the technical confirmation/innovation program, she said.

I. Internal Operations Charged to Power

Bryan Crawford (BPA) went over the changes and additions to the March 1 meeting packet. The programs designated with stars on the organizational chart on page 8 are currently involved in the Enterprise Process Improvement Project (EPIP), he said. The other functions will be involved later on – all of Corporate will go through EPIP at some point, except for General Counsel, Crawford stated.

The information on page 1 is to clarify any confusion about Corporate FTE, he continued. Crawford elaborated on the explanations provided about the changes in Corporate FTE, pointing out that 2000-2002 "was a growth period." There was increased need to support the business lines, a security build up post September 11, a transmission infrastructure effort that required support, and we added F&W staff to enhance management and communications, he explained. Crawford detailed the additions and decreases in Corporate FTE, explaining the increase from 731 FTE in 2002 to 797 FTE in 2005.

Why isn't General Counsel going to be included in EPIP? Mark Thompson (PPC) asked. KEMA (consulting firm) did not recommend it be included, Crawford responded. Also, it is a small support staff of about 50 people, and there is not much to be gained in efficiencies there, Kathy House (BPA) added.

Terry Esvelt (BPA) said the explanations on page 12 were developed in response to several questions at the last meeting. It looked like the business lines were doing much better at holding down costs and FTE than Corporate, but when you get into the details of organizational movements from the Business Lines into Corporate over time, we look much like the rest of BPA, he said.

Crawford pointed out that changes in Corporate lag changes in the business lines. If there are reductions one year in PBL, for example, it will take until the following year for the reductions to show up in Corporate, he said. EPIP will also bring down the Corporate FTE numbers, Crawford indicated.

But you will have to set a revenue requirement for the rate case, so won't you have to make assumptions? Kevin Clark (Seattle) asked. Yes, that's correct, Crawford answered.

He moved on to page 17 and the detailed costs associated with each of the general and administrative (G&A) cost pools. He pointed out that on the newly revised spreadsheet for Corporate expenses, TBL and capital were added. This allows you to add up all of the expense associated with a particular function, Crawford said.

There were questions about the spreadsheet and how the numbers relate to those elsewhere in the packet. Crawford explained how the Corporate and Shared Services costs are allocated to the business lines. Could you post this spreadsheet in Excel? Clark asked. Manary said she would send the spreadsheet to people who are interested, but would not post it in Excel.

Page 23 explains the IT consolidation and the difference between the number on the Corporate cost chart for FY 2005 ($58.5 million) and the baseline budget ($67.3 million), Crawford said. The $58.5 million dates back to the middle of last summer, he explained. The consolidation was complex, and it took a while for all of the numbers to catch up with the reassignment of FTE and functions; it took until January for everything to shake out, Crawford said.

The chief operating officer wanted the IT chief to have the whole picture before he started looking for cuts, Crawford said. IT has committed to a 25 percent reduction of capital and expense budget dollars, off the $67.3 million baseline, over the next 18 months, he stated. We will be able to factor in new estimates by the end of April, Crawford said, adding that it will make a big difference where specific cuts are made – they could affect PBL and TBL differently and may be either in capital or expense. "It's safe to say we won't get a 25 percent reduction without substantial changes in IT operations," he stated.

Joe Hoerner (Tacoma) asked for clarification about the baseline figures from which cuts would be made. It is $67 million expense and $30 million capital, Crawford responded. Our goal is to have a good feel for the numbers by the end of next month, with the distribution to PBL and TBL, he said. IT is the furthest along in EPIP, Crawford added.

II. <u>Technology Confirmation/Innovation (TCI) Program</u>

John Holmstrom (BPA) pointed out that the budget for the TCI program is on line 27 of the spreadsheet and starts at $250,000 in FY 2006 and ramps to $4.1 million in 2009. We prepared a four-page backgrounder on TCI as well, he said.

How did you come up with the funding level? Clark asked. "There isn't a magic number we're shooting for," Holmstrom responded. BPA's technology budget has been as high as 1.5 percent of revenues and as low as the current one-fifteenth of one percent, he said. The industry has been depressed in terms of the attention paid to technical innovation, and we are looking to take a more aggressive approach, Holmstrom explained. He pointed out that BPA currently has about $5 million to $6 million dedicated to technology-related activities within programs, including efforts at Corps of Engineers, Bureau of Reclamation, and Energy Northwest facilities. Holmstrom said the projection for TCI is to ramp up gradually to between $9 million and $15 million by 2011 or later.

Where do we see those dollars now? Stephany Watson (Krogh and Leonard) asked. They are part of O&M budgets, Manary answered. Why the new line item? Watson asked. These activities have been a source of arbitrary cuts in programs and relegated to the background, Holmstrom replied. Management wants a more focused effort, he said. This won't be a stand-alone, independent operation – it will be networked with other programs, Holmstrom added.

Is there a demonstration of cost-effectiveness with these efforts? Thompson asked. Yes, on a portfolio basis, Holmstrom responded. "Not every project will pan out," but overall we expect successes will overcome any losses, he said. BPA has not been good about reporting the value and results of this type of expenditure, Holmstrom added. He pointed to accomplishments listed in the backgrounder and how they have contributed to agency savings and eased regulatory restrictions.

What is the proposed allocation of funds between PBL and TBL? Clark asked. It will probably be an even split, but will vary from year to year, Holmstrom replied. The proposal is to have a split with truing up later on to assign costs appropriately, he said. The idea is that we would have requests for proposals, and once we have a technology road map, we can target projects to particular areas, Holmstrom explained.

It looks like the power rate impact is about $1.4 million annually in the next rate period, Clark observed. That looks about right, Holmstrom answered. He acknowledged that it is difficult to identify ahead of time where expenditures will be made. Opportunities can present themselves that we know nothing about today, Holmstrom wrapped up.

III. Shared Services

Laura White (BPA) presented the Shared Services costs to PBL, saying the function considers itself to be a strategic business partner to the business lines. We try not just to provide service, but also to advise on ways to increase efficiency and reduce costs, she stated.

What Shared Services provides to the agency falls into two categories, White explained: workplace services, such as building leases, space planning, mail distribution, printing, and office equipment and supplies; and personnel services, such as recruiting, benefits, performance management and training, and harassment-free work environment. She went over the costs for the services from 1998 to forecasts through 2009, and noted that "the huge drop" between the high in 2002 and the low in 2005 reflects the migration of the purchasing function and the IT transfer.

White's presentation included a historical look at FTE and the distribution of costs to the business lines. In 2005, the split is forecast to be Transmission, 48 percent; Power, 17 percent; and Corporate 35 percent – the increase for Corporate over previous years is offset by decreases in the business lines, she noted. White explained that the distribution of costs is based both on the number of people served and by actual usage of services. She went over the history of Shared Services costs to PBL by functional area and the volumes of services provided.

The forecast costs to PBL through 2009 reflect "very small incremental changes" primarily due to inflation, White stated. We are a small part of PBL costs, she added. A pie chart detailed the 2005 forecast of $6.6 million to PBL, the biggest piece of which is rents and leases, White noted.

Esvelt pointed out that Shared Services expects to decrease the outlay for rents and leases. When TBL moved its workforce to Vancouver, it left vacant space in the headquarters building here in Portland, he said. The plan is to fill this building back up by moving people fromVancouver, Esvelt stated. We will be utilizing the space better, he said. The expense for TBL will go down with less space leased in Vancouver, and the expense for PBL will go down since TBL staff will share the lease here, Esvelt explained.

White went over lists of reductions and ways Shared Services has provided services at lower costs, along with reductions that have been made in services offered to clients. She detailed the risks Shared Services has in meeting its forecast budget, as well as opportunities for savings. Hoerner asked when moving costs would be incurred, and Esvelt said the moving costs would be in 2006, with rent/lease savings reflected in 2007.

Clark asked for more detailed information on the total Shared Services costs. Could you give us the total breakdown – we only see $11 million here, he stated. We'd also like to see the federal cost of living adjustment (COLA) figures, Clark requested. David Steele (BPA) listed the COLAs from 2000 (5.01 percent) to 2005 (3.61 percent) and said that Corporate used 3.0 percent in its forecasts of future years.

In summary, Shared Services' costs and FTE are flat, except for inflation, White stated. We work closely with PBL to manage costs, she said, listing examples of recent process improvements that have saved the agency money, including online distribution of publications.

The meeting adjourned at 10:30 a.m.

Follow-up questions and information requests:
Responses to questions and requests for information received throughout this process will

be posted on the Power Function Review Web site on an ongoing basis. The Web address is www.bpa.gov/power/review.

1. Provide more detailed information on the total Shared Services costs. Including the total breakdown.

Bonneville Power Administration
Power Function Review Technical Workshop
March 15, 2005

PFR-007
APR 0 3 2[illegible]

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 30

Columbia Generating Station O&M
Corps of Engineers and Bureau of Reclamation O&M

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

Introduction

Michelle Manary (BPA) opened the meeting and called attention to "Scoresheet" and "Decision Forums" handouts. These were prepared to respond to feedback that people wanted a delineation of issues that impact the 2007-2009 rate case budget (Scoresheet) and information on how and when to comment on various issues (Decision Forums), she explained. The sheets will be updated as new information comes along, Manary indicated. She also said responses to questions from the opening workshop and on conservation and renewables would be posted on the website this week. There is a link on the PFR site to questions related to fish and wildlife (F&W), Manary added. She told participants the draft conservation paper due out in mid April will address the post 2006 conservation program structure and the renewable credit, and risk associated with IOU benefits will be part of the risk mitigation workshop and will be decided in the rate case.

I. Columbia Generating Station O&M

Andy Rapacz (BPA) went through a handout on Columbia Generating Station (CGS) O&M. He noted that CGS O&M is forecast to be $284 million annually in 2007-2009, about 11 percent of the PBL rate structure. BPA purchases 100 percent of the output of CGS and pays all operating costs for the plant, Rapacz said. Accounting distinctions between Energy Northwest (EN) and BPA – cost versus cash budget and different fiscal year – explain why numbers in the presentations will not match perfectly, he noted.

Rapacz went over a bar graph of historical costs and projections for 2007-2009, noting that the estimates are presented with and without debt-financed capital to show the impact of using debt, rather than revenue, financing. He said the amount that could be capitalized is $34 million in 2007, $12 million in 2008, and $14 million in 2009.

How are the debt-financing decisions made? David Hoff (PSE) asked. Don Carbonari (BPA) said BPA's financial analysts are working on a decision now. We are doing analyses and running the repayment model, he explained. When we have our results, we will present them – maybe in a session like this, or if they're clear enough, we can post them on the website, Carbonari said. BPA works with EN on capital decisions, he added. Is it a joint decision? Hoff asked. “That’s fair to say” – we negotiate our differences if any exist, Carbonari answered.

From our standpoint, capitalizing is an important issue, Jim Gaston (EN) said. Many other nuclear plant owners are more aggressive in capitalizing purchases, and whether we capitalize as much as others do makes a difference in how we look in benchmarking exercises, he indicated.

The large variation in CGS costs from year to year is a result of outage versus non-outage years, Rapacz continued, adding that some outage costs are paid in non-outage years. He went through the categories of expenses, which include O&M, fuel, capital, Decommissioning Trust Fund contributions, and insurance. The totals are $317 million for 2007, $248 million for 2008, and $286 million for 2009, Rapacz indicated.

A graph of actual generation versus rate case estimates showed that in each year since 1999, CGS has generated more than forecast. BPA is conservative with its estimate of CGS generation, Rapacz explained.

He listed the drivers of the increase in the CGS O&M budget and the risks in terms of potentially greater increases. Rapacz also pointed out that “a tremendous amount of benchmarking” goes on in the nuclear industry, noting that “fleet plants” have a cost advantage over plants like CGS that operate as stand-alone facilities. There is about a 15 percent difference since the economies of scale are not available to single, stand alone plants, he said.

The cost of nuclear fuel is escalating, due primarily to the increase in uranium costs, Rapacz went on. EN has the opportunity to mitigate the increase by undertaking a pilot project for DOE to recycle uranium tails, he explained. The project involves the acquisition and processing of what is now uranium waste for use as reactor fuel and could save EN up to $30 million over 10 years, Rapacz said. There will still be an increase in the cost of fuel, but it would be larger without the uranium tails project, he added. Rapacz explained a table on uranium procurement scenarios and savings predicted each year with the pilot project. We are close to starting the project, but are still analyzing what the best financing model would be, he said.

The financing examples on this handout are just that – once you run the numbers through the repayment study, the outcome could change, Carbonari said. Our plan is to finance the cost of the tailings project when we do our debt optimization refinancings, he said.

I get the feeling the calculations on financing are in some way influencing the decision to go after the fuel savings, Doug Brawley (PNGC) commented. The fuel savings ought to be captured as soon as possible, and then BPA can figure out how to finance the project, he said. That’s true, Rapacz agreed. But we have fuel contracts right now that are a good deal, and we will be maximizing our use of those first, he said. The tailings pilot is expected to cover fuel for four CGS refueling cycles, or eight years, and would kick in about 2009, Rapacz said.

Why are decommissioning costs going up? Pete Peterson (PGE) asked. There are several reasons, but one is that the trust fund is not earning as much as it was before, Rapacz responded.

He went on to explain that the 2007-2009 budget includes dollars for license renewal. The CGS license expires in 2023, but EN can apply with the Nuclear Regulatory Commission (NRC) for a 20-year extension, Rapacz said. We have a window from 2003-2018 to apply, and there is a question about when to do that, he said.

Vic Parrish (EN) led off a presentation on CGS and EN's process in planning and budgeting for the plant. He said a big challenge is managing a stand-alone plant – only six utilities in the country have single nuclear plants. Parrish explained recent actions taken by EN to support the region and keep costs down. "There is a lot of emotion and discussion around the debt optimization program (DOP)," he acknowledged, but "it's the right thing to do." Among other actions, EN freed up hundreds of millions of dollars in bond-fund reserves and has a goal of under-running its 2005 budget by $5 million, Parrish said. EN has taken a fresh approach to cost-competitiveness, and the region is seeing the results of that initiative, he stated.

With regard to relicensing, Parrish said EN has to make a submittal by 2014 – "you don't want to wait until 2018." There are risks associated with waiting to pursue a new license, he said. The NRC "is pumping these through in about 14 months" right now, according to Parrish. And, he pointed out, decisions about equipment replacement and upgrades are affected by whether or not EN is going to pursue relicensing. We estimate it will cost $14 million to go through the relicensing process, Parrish indicated.

At some point, the region "has to make a macro decision" about whether to shut the plant down, Kevin Clark (Seattle) stated. When you consider the costs of a shutdown and replacing the energy, "it's a pretty easy equation," Parrish responded. There is enough objective evidence to see the economics of continuing to operate the plant, he said.

How is the decision about relicensing being made? Clark asked. For us, the decision is clear – we want to relicense the plant, Parrish stated.

What about "extraordinary" costs associated with relicensing? Clark asked. We don't anticipate any, Parrish responded. It could take an $80 million investment to keep things going with a new license, but that's within the budget – we could have to replace things, he acknowledged. Parrish suggested if CGS were to seek a relicense, it would be worth exploring a plant uprate, which could mean a 15 percent increase in power production capability. It would be a $150 million upgrade, but if you extend the license, the cost-benefit calculation looks quite different, he said.

You could renew the license and still decide to shut the plant down – the question is whether the flexibility is worth $14 million, Parrish said. Our budget numbers reflect making a decision next fiscal year, he said. If we decided not to renew, we'd take that money out of the budget, Parrish added.

He went over a list of unbudgeted costs for CGS and pointed out that security is a big issue in the nuclear industry. EN has spent $22 million on security since September 11, Parrish said, and it is possible the NRC could issue even more stringent requirements. Congress will be addressing the issue, and there should be "a reasonableness factor" incorporated into new directives, he said. We don't have a lot of control over whether we implement security directives, and the costs go to ratepayers, Parrish pointed out. We need to define what is enough – "it's a huge unknown," he stated.

The cost drivers in CGS' budget include an Independent Spent Fuel Storage Installation (ISFSI) because there is no national disposal site yet, Parrish reported. The region has paid $122 million toward develop the site at Yucca Mountain, which has not opened, and EN had to build the ISFSI to store spent fuel, he explained. Equipment obsolescence issues, staffing, and regulatory costs are among the other drivers, Parrish said. With regard to staffing, he said EN's work force is aging, and it's a competitive industry in which to find new employees. EN is average in the industry with regard to compensation and incentives, according to Parrish.

This is an important year for us with the outage – we have to have a high probability of success, he continued. With regard to outage costs, the nuclear industry is unique in that charges for some services are based on "a value proposition," Parrish said. By that, I mean providers charge according to how much more power a plant will be able to produce once the service is accomplished, and "they want their cut," he explained. Fleet operators have more leverage to negotiate such charges, Parrish added.

He went on to explain the continuous nature of benchmarking in the industry and where CGS stands among its peers. CGS staffing numbers are high relative to comparable plants, and Parrish said FTE is coming down by 51 this year and by 80 in 2006. Our goal is to be above average in performance and to be in the top 50 percent of the best performing plants, he stated.

Asked why CGS costs had escalated sharply since the late 1990s, Parrish said he went too far with cutbacks in the 1990s. We are catching up and taking care of things that were put off then, he indicated.

Al Mouncer (EN) explained the planning cycle and went over budget objectives. The 2006 O&M budget proposal, which will go to the board in March, is $199.5 million, he said. EN will finance about $5 million of $8.1 million in capital projects, Mouncer said.

Clark asked about EN's capitalization rules. Gaston said a new capitalization policy is being developed and would be in effect in 2007. Can you provide BPA numbers for the rate case that reflect the new policy? Clark asked. We don't know yet, Mouncer said. We'll work to get that done as soon as possible, Parrish added.

Mouncer noted that the 2006 budget reflects a $6 million decrease from the previous long-range planning target. He detailed areas of increase for 2006 and costs within the four major budget categories: fuel, A&G/benefits, projects/capital, and baseline. Lyn Williams (PGE) asked about the CGS payroll. We view compensation as a total package that includes salary, benefits, and incentives, Parrish responded. The integrated compensation package includes meeting performance targets, he said. Williams asked for a total payroll figure.

Lindsey Manning (Shoshone-Paiute Tribes) asked why the cost of nuclear fuel has increased so much. It's primarily due to the cost of uranium, Rapacz replied. The biggest impact to uranium is that Russia is holding back the amount it previously supplied to the market, and in addition, China and other Asian countries are building nuclear plants, he said. The industry has been living off of fuel inventories, and those are gone, Parrish added.

EN will pay over $9 million in 2006 for nuclear fuel disposal, Mouncer said. DOE committed to having a repository by 1998, but is "woefully behind" in providing one, he explained. Like other nuclear utilities in the country, EN is suing DOE and trying to recoup costs of the ISFSI it was forced to develop to store spent fuel, Mouncer said.

He described EN's multi-layered "activity based management" approach and its nine categories of activity. The method provides us a way "to pull silos of costs" from throughout the organization into one activity, Mouncer explained.

Training is a major focus at EN, with nuclear operators in training one week for every six worked, Parrish said. Training is a big investment – we can't afford to lose people once we have invested in training them, he said. We are required to have an accredited certification program for nuclear operators, and every year, they must pass a test or risk losing their license, Parrish said. EN's training institute is open to others, he said.

Mouncer explained the priority assigned to categories within the $96 million baseline budget, with Regulatory activities as Priority One and Discretionary activities as Priority Four, and he went through the specific items within each priority.

Gaston described the $17.2 million projects/capital budget and initiatives in the 2006-2011 long-range plan. According to the plan, EN projects $118 million in budget reductions during the period, he pointed out. The reductions do not come without some risk, Parrish said, explaining the decision not to replace the main condenser, which saved $17.5 million, even though it puts copper into the reactor cooling water. We are outside the specifications for copper, but we don't believe it is an issue for us – we have not had a fuel failure, the main risk from copper in the water, in seven or eight years, he said.

In the last rate period, you absorbed inflation, Clark commented. Why are you putting it back in? he asked. It was our judgment we needed to put it back – we couldn't continue to absorb it, Parrish replied.

We want to bring the costs down in this rate period, Clark stated. I'm nervous that BPA will import your numbers into the rate case, without your future targets for reduction, and set our rates accordingly, he said. Is there a management target for O&M? Clark asked. We look at this every year, and we now see there are things we have to do to maintain reliability, Parrish answered. If you don't spend the entire O&M budget, we'll still pay for it in rates, Clark said. Can't you find 10 percent in reductions, things you're unlikely to do? Can we put those numbers in the rates? he asked.

We'll do everything we can, but we want to be realistic, Parrish answered. These reflect our best professional judgment about what's needed, he said.

This is a timing and rate design issue, Williams commented.

It's in everyone's interest to live with what EN gives us, Jim Litchfield (LCG) stated. If not, it will go into BPA's risk management costs – if EN goes too far with cuts, that's a problem too, he said.

Gaston continued through the cost figures and described the process for plant modifications and major maintenance programs. He also went over a list of items that are not included in the long-range plan, but are on the horizon and may need to be done.

Your costs from 2001-2004 were $211 million per year, but from 2005-2010, they'll be $228 million, up $17 million per year, Clark pointed out. Some of this is due to an aging plant, Parrish said. Our job is to do what's right, he added. The implication with our O&M budget is not just that we are able to fix a problem if it arises, it could be a question of whether we are allowed to operate at all if we have a problem, Parrish said. And "a shutdown is untenable," he said. We are here trying to get the costs down to our ratepayers, Clark responded.

Rapacz wrapped up with a look at the CGS O&M costs, noting that the reductions in 2007-2009 could be greater, depending on what is capitalized. What is the timing on the capitalization decision? Peterson asked. June will be the target to have new numbers, Rapacz responded. The joint customers applaud EN's efforts to cut costs, Peterson said.

II. Corps and Reclamation O&M

We heard at the Sounding Board that there is interest in having regular meetings with the Federal Columbia River Power System (FCRPS) partners on budgets and performance, Mark Jones (BPA) said. We like the idea, and would offer to start those meetings – perhaps next fall, he suggested. We would also like to offer to set up visits to the hydro plants for you to see how the specific projects are managed and discuss issues that are being worked on, Jones continued. There are people here today from the Corps and Reclamation who could set up those visits, he said.

<u>O&M Program</u>

Mike Alder (BPA) went through a list of O&M program benefits and results, noting that unit availability is improving and reliability is increasing. He pointed out the importance of the regional partnership that has developed among the three FCRPS agencies. Alder described the FCRPS, locating the projects on a map, and offered a history of the asset management program, which began with the 1998 cost review and a recommendation that the agencies develop and implement an integrated capital/asset management strategy. He said Congress also referred to the cost review recommendation in 1998 and directed BPA, in conjunction with the Corps and Reclamation, to develop an asset management strategy.

The program milestones include signing direct-funding agreements between BPA and the Corps and Reclamation, and creation of Joint Operating Committees, Alder said. The program has resulted in improved working relationships and enhanced collaboration among the agencies – we are three agencies in three different departments of the federal government, but we are working together closely to manage the FCRPS, he reported.

Alder described the components of O&M program management and explained the rationale for the program, including the need to address an aging hydro system. The material condition of equipment varies throughout the system, but there has been a lack of capital investment over the years, which affects system performance, he indicated. Alder offered charts of the historical forced outage factor and unit availability. When we make improvements, we take plants out of service, which is reflected in the unit availability numbers, he noted. The graph is megawatt-weighted, so when you take out a unit at Grand Coulee, the line goes way down, Jones pointed out. Clark asked for information about the lost value of generation when units are unavailable. We take that into consideration when we plan outages, Alder responded.

Jones explained the two goals of the asset management strategy: restore reliability of the system to industry standards or better and enhance revenues by $50 million annually through efficiency gains or cost reductions. He described the Integrated Business Management Model and how it is used to implement the program, and he offered an example of an O&M budget and a table of performance indicators, as well as a strategy map that states as the goal of the program, "maximize value to the region."

Pete Gibson (Corps) said the FCRPS agencies conducted an asset management process review and are working to integrate the pieces into an overall asset plan based on activities that provide the most value. We are looking at all of the components from a system perspective to see where we want to go, he said. We also realized we have to start thinking more long term, Gibson explained. We have not had a capital replacement program, for example, he added. We are asking for your input on the direction we are taking, Gibson said.

We understand that you are maintaining assets for the long run, Clark said. But he suggested the need for "a creative approach" – you can't defer maintenance, but you don't need "to throw everything at it" either.

We are using life-cycle analyses to help point the way and prioritize actions, Gibson responded. We are asking "what has the most value," he said.

There are a couple of innovative ways we approach a determination about where to invest, Phil Thor (BPA) explained. For example, you don't want to replace a piece of equipment before the end of its useful life, but predicting failure is difficult, he said. We are using HydroAmp, a condition assessment tool, to identify where best to put money, Thor said. The tool looks at things like the risk and consequence of a failure, he said.

How are you getting smarter at finding the most cost-effective fixes? Clark asked. We're always using the best information and analyses that we can, Thor responded.

We used to procure components by district, but a year ago, we went with regional "IDIQ" contracts, Gibson added. That gets us the best price for products, he said.

I'm interested in how you factor in non-power aspects, Litchfield said. The McNary modernization project provides an example, Thor indicated. As part of the modernization planning, we did an economic study to look at replacing the turbine runners, he said. We established as the highest criteria that the replacement had to have no or minimal impact on fish passage, Thor explained. The result was that we ended up soliciting bids for a diagonal-flow, minimum-gap runner blade, he said. So you are paying more for an environmental advantage, Litchfield commented. Yes, we are building in the non-monetary value of an economic tradeoff, Thor said.

How did Congress direct you to come up with an asset management program? Hoff asked. It was in Congressional report language that was part of an appropriations bill, Thor responded. Previously, we had not blended capital and expense, Gibson said. It took two or three years, but we came to the "ah ha" realization that capital and expense had to be blended into an asset management model, he said.

Thor explained the table of performance indicators on page 18. Our objective this year with asset condition is to get baseline data on six pieces of equipment, he said. The HydroAmp tool will become part of our maintenance program, Alder said. We have established performance indicators since 1998, he added. Can we get those seven years of data? Clark asked. Alder said he could provide that data.

Using your Integrated Business Management Model, how do you make adjustments as a result of performance? Clark asked. We do adaptive management, Jones replied. We plan, perform, measure, and then adjust if needed, he said.

Where does increased expenditures link to better performance? Brawley asked. Where does the benefit show up? he inquired. Others pointed to the forced outage factor and said they did not see a correlation between expenditures and improvement. "We are not over the hurdle with system replacements," Thor responded. We have an active capital program during this rate period and beyond to get to the plateau – it's a slow-moving indicator, he said, referring to the forced outage factor. For the capital program, there is a huge rate of return for the improvements, Alder added.

How do we change the dynamic to get even more value? Clark asked. Can the performance indicators affect the way money moves between objectives? he asked. For instance, set up an incentive system and reward good performance with more funding, Clark suggested. We are trying to see you extract more value going forward, he stated.

Gibson said recent steps, such as the sharing that now takes place among FCRPS agencies, represent "a quantum leap" forward. None of the plants has enough money to do everything, so determining expenditures is always a process of setting priorities, he said. In "the appropriations mind set" you don't want to turn back money, but now we are moving money to add value, Gibson said. We are now looking at the FCRPS as "a holistic system" and not agency by agency, each with its own measuring stick, he pointed out. "We've made a quantum leap," Gibson reiterated.

Williams said customers are seeing a fractured process. We have a strategy team together, and we've met with PGE, for example, to improve and implement best practices, Jones responded. We've done bits and pieces, but it isn't a complete program yet, he acknowledged.

You've gotten the teamwork in place, now is there a way to be more effective with maintenance? Clark asked. How about giving an incentive by allowing those who are saving money to keep it for more projects, he suggested. The next leap forward is "to release the creativity," Clark stated.

Alder continued with his presentation, saying that Reclamation's O&M program is at baseline to maintain reliability and unit availability, but the Corps is below baseline. The historic level of capital investments at Corps plants has lagged far behind the industry averages, he said, noting that only $8 million in capital investment was made in the Corps' FCRPS projects in 1998.

Brawley asked why Reclamation's unit availability dropped so steeply in 2004. We had outages at Grand Coulee, and that "drags everything down," Terry Kent (Reclamation) responded. "The nosedive" was due to making capital investments at Coulee, he said.

We try to do outages when there isn't water to generate – we schedule them for times when we are not moving water out of Coulee, Kent added.

I don't see the Corps argument that they aren't funded adequately, Clark stated. The growth in Biological Opinion (BiOp) requirements has been a priority for the Corps, with hydropower O&M a lower priority due to limited funds Alder pointed out. The goal for the Corps is "to get beyond breakdown maintenance," he said.

Alder listed the FTE for the Corps and Reclamation O&M, and Clark asked for information about FTE associated with the capital investment contracts. What is the value of knowing that? Gibson asked. Once the bid is awarded, it's up to the contractor to decide how many FTE to use, he indicated.

Where are you evaluating the bid in terms of the split between personnel and materials? Williams asked. We have a technical team that does that evaluation, Gibson said. We could provide the government's numbers for contractors, but we'll have to see about how to address the others later, Jones said.

Alder reported on where the FCRPS stands with regard to industry peers, stating that the FCRPS is below the expected costs for O&M, excluding the PA&R category. He noted that the benchmarking category for public affairs and regulatory, where FCRPS costs are higher than the rest of the industry, includes fish-related costs.

You are benchmarking against others that are likely vertically integrated utilities, Clark commented. Is there any candid discussion of duplication across the agencies? he asked. The cost review in 1998 said there could be efficiencies in combining some agency functions, Alder responded. We are different agencies, with different missions and cost structures, he pointed out.

We have swapped people within the agencies to do specific tasks, Gibson added. We've formed interagency teams to better coordinate functions – "we don't try to change each other," but we look for ways to be more efficient, he indicated.

Is there a push, for example, on river forecasting? Clark asked. We are looking at opportunities with "the big stuff," Kent responded. Clark recommended the agencies build in incentives to change the ways things are done and to become more efficient.

Alder moved on to the forecasts for 2007-2009 and the drivers of costs since 1997. The Grand Coulee cost reallocation increased costs by about $6M per year as a result of the change in costs allocated to power from 70 to 92 percent. We've seen a significant increase for fish operations, as a result of the BiOp, as well as for security, he noted. Clark asked about a $10 million per year increase in the Corps' direct funding, and Alder indicated that BPA agreed to up the Corps budget to address the under-funding that went on in previous years. We wanted to get on top of the maintenance needs, he stated.

We're trying to set a revenue requirement for the rate case, Clark said. We'd like to see something that covers asset management, but not without incentives – something that goes with the old budget plus an incentive for performance, he indicated. The figures for 2007-2009 are the baseline for what we think we need, Alder responded.

Your numbers show the Corps and Reclamation are about equal with regard to forced outages, Clark pointed out. We're trying to manage to get to "stretch target" levels, Kent stated. Can we build those targets into the rates? Clark asked. Our new figures do reflect those targets, but we have some significant resource requirements coming up, Alder responded.

He listed the drivers of change for the 2007-2009 period, and Lon Peters (PGP) asked about a $2.5 million expenditure for NERC/WECC compliance. Hiroshi Eto (Corps) said the expense is for several things, including gathering more data on outages. We also have to do relay testing and system audits, Kent said. There is a group looking at the requirements and where the system stands now, Jones explained. The expense relates to meeting new and existing requirements, and it's our best estimate of what it will cost to be in compliance, he stated.

The upcoming period includes the expense of a security system mandated by the Department of Defense and an environmental compliance system mandated by EPA and the Corps headquarters, Alder noted, and he pointed out there is no BiOp for the Willamette yet, which could add additional costs. There are opportunities for efficiencies, he said, going through a list on page 33 and pointing out that the Power Plant Efficiency Initiative has added 80 aMW to system capability. And there are risks, including uncertainty about many of the items already listed as the drivers of change, Alder explained.

He went over a table that attempts to get at the rate effect of the O&M program increases. Without the program, we estimate rates would be between 1.78 mills and 2.15 mills higher in the next rate period, Alder concluded. I'd like more detail on your assumptions for that calculation, Michael Early (Alcoa/CFAC) requested.

The facts don't back up your assumptions, Clark stated. I don't see the relationship between the dollars for O&M and the forced outage factor, he said. "I can't connect the dots" in tracking from the investments to availability and the rate effects, Early added.

The bottom line for the O&M program is that the $242 million expenditure is about 3 mills in rates for the 07 to 09 period, and it's producing $2.5 billion in revenues while providing reliable power to the region, Alder concluded.

<u>Capital Investment</u>

Thor described the capital investments being made to meet the two asset management goals: increased generation reliability and increased generation efficiency. With regard to industry benchmarks, we are investing a lot less than other systems, he said. The only category of investment in which the FCRPS exceeds its peers is in parks and F&W, Thor noted.

How did you decide you needed a 34 percent increase in capital investments? Clark asked, referring to page 55, the capital investment program budget for 2002-2009. We estimated what we needed to preserve the system, Thor responded. But we didn't want to budget more than we could execute, he added. The numbers were suggested in the asset management strategy, Thor said.

He explained a graph of the energy benefits from the capital investment program and a comparison of the forced outage factor, with and without the capital investment program. The difference in the forced outage factor without the capital investment program would be $75 million less revenue annually under average water conditions, Thor stated. He went over examples of how capital is being invested to achieve efficiency gains: the turbine runner replacements at Grand Coulee and McNary. The capital investment program has prevented degradation of the system and decreased rates, Thor said. We project the rate reduction to be between 0.97 mills and 1.57 mills in the next rate period, he explained.

Thor went over a table of the projected net prevent value (NPV) and internal rate of return (IRR) for the capital investment program from 2005 to 2014. The overall projection for the NPV/IRR for generation reliability investments is 22 percent and for generation efficiency investments, 150 percent, he said. Another calculation, which Thor called "a thought experiment," shows that the level of investment needed to sustain the existing system in perpetuity would be $110 million a year. This is another way to hone in on the appropriate budget, he said.

"That's a good story," but the data does not back it up, Clark stated, pointing to the graph on forced outages. It doesn't show you are gaining improvement, he said. It looks like we're spending $97 million to save $75 million, Joe Hoerner (Tacoma) said. If your forced outage factor were going down, I'd say spend more, but it is going the other way, Clark said. I don't see evidence that you need additional investment – you have not made a case for the 34 percent, he said.

The forced outage factor may not be the best measure of what we're achieving; it's a lagging indicator, Thor responded. We backed three units out at Grand Coulee, and it pushed the curve way down for 2004, Kent responded. And there's more to this than forced outage, Eto added. The condition of the units is driving investment, he said.

The forced outage factor is not the best measure, Litchfield stated. You need to show under what conditions you actually lose revenue, he said. How do you measure when the outage actually causes a loss of revenue? Early asked. We have a tool that calculates the value of availability, Thor replied.

One of the questions that is not answered here is, what is the strategy behind direct funding, Williams commented. We want more direct control in the region over where the investments are made, Jones replied. This gives us more control, he stated. In the past, whatever Congress appropriated for the FCRPS, we got the bill, Thor added.

Do you still have appropriated costs to pay? Williams asked. Yes, but not much on the expense side, Alder said. Congress appropriates the Columbia River Fish Mitigation (CRFM) capital costs, and BPA pays for those, Thor said.

Gibson asked for suggestions on the presentation to managers, and Clark offered several, including adding how the agencies are being innovative with the O&M expense; better explaining the $126 million on page 55, which is currently labeled "unclassified reliability investments"; and clarifying "the hopper" of projects. Williams said she thought management would see the Integrated Business Management Model as going in the wrong sequence. You usually start with strategic planning ahead of allocating resources, she pointed out.

For $2.5 billion in revenues at a 3 mill cost, we are providing service for you all, Gibson summed up.

The meeting adjourned at 4:20 p.m.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on an ongoing basis. The Web address is www.bpa.gov/power/review.

1. Please provide the data for the seven years performance indicators referenced on page 18 of the Corps/Reclamation presentation.
2. Provide more detail on the assumption that without the O&M program increases the estimated rates would be between 1.78 mills and 2.15 mills higher in the next rate period.

Bonneville Power Administration
Power Function Review Management Level Discussion
March 16, 2005

PFR-008
APR 01 2005

Rates Hearing Room, BPA Headquarters, Portland, Oregon
Approximate Attendance: 35

Columbia Generating Station O&M
Corps of Engineers and Bureau of Reclamation O&M

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

I. Introduction

Paul Norman (BPA) welcomed the participants and noted that the topics for the next two days would cover "large hunks" of BPA's power costs. He called attention to a letter in the packet, sent to Public Power Council (PPC) manager Jerry Leone, that addresses several concerns about the PFR and the need for more clarity about decisions that will be made. In response to the PPC, as well as others' comments, we have provided "a road map" directing people to the appropriate comment and decision forums, he said. In most cases, the forum is the PFR or the rate case, but there are some others, Norman noted.

In addition, we've heard comments that people appreciate the information we are providing in the PFR, but would like to have the policy decisions highlighted, he continued. We have developed a matrix, which we're referring to as "the scoresheet," that lays out the policy questions, Norman said. We intend to continue to update the scoresheet as the PFR moves along to clarify where the choices are, he said.

A third comment we've heard is that BPA ought to come back with a proposal at the end of the PFR, and we have determined that we will put out a draft proposal and provide an opportunity for comment on it, Norman reported. We will have meetings of both the technical and management groups on the proposal before we make a final decision in mid-June, he said.

Every customer we talked to supports establishing a rate target, and public power has coalesced around 27 mills, Norman went on. I thought we ought to discuss risk mitigation before we talk about a target, he stated. I understand the message from public power, but if we do set a target, BPA isn't comfortable with setting a target ahead of the risk discussion, Norman said.

II. Columbia Generating Station O&M

Andy Rapacz (BPA) said his presentation would be oriented to the policy choices involved with Columbia Generation Station (CGS) O&M funding. CGS is "a significant part" of BPA's power rate structure at $284 million or 11 percent per year, he said. Rapacz pointed out that BPA purchases 100 percent of CGS output and pays all O&M costs. To explain differences in the numbers BPA presents versus those in the Energy Northwest (EN) material, he noted that the two agencies operate on different fiscal years and that EN budgets are cost, rather than cash.

Rapacz proceeded to a history of CGS costs and said BPA has not made decisions yet about debt financing CGS costs during the next rate period. We have assumed we would revenue finance in 2007-2009, he said, and he noted that BPA's repayment study would help inform the decision. Rapacz reported the amounts that could be financed in 2007-2009 as $34 million in 2007, $12 million in 2008, and $14 million in 2009. Norman clarified that debt financing would entail EN, not BPA, borrowing.

Joe Nadal (PNGC Power) asked about EN's capital policy. We can finance anything with over one year of life, Al Mouncer (EN) responded. And we try to be consistent with the rest of the nuclear industry, since we are benchmarked against our peers in the industry, Vic Parrish (EN) added. We assume your priority is in making a good business decision, not staying consistent with the industry, Steve Eldrige (Umatilla) commented.

Rapacz went through the categories of CGS costs, drivers of the projected increase, and the role of benchmarking in the nuclear industry. He pointed out that as a stand-alone plant, CGS is 15 percent more expensive to operate than "fleet plants." Among the risks of future cost increases, the price of nuclear fuel could go up significantly, Rapacz said. EN's procurement strategy is to enter long-term fuel contracts and buy very little on the spot market, he said. Since January 2003, however, the price of uranium has doubled – Russia has stopped supplying the market, fuel stockpiles are depleted, and China and other Asian countries plan to build nuclear plants, Rapacz explained. Not enough uranium is being mined to fill the need, he stated.

In order to mitigate the escalating fuel price, DOE approached EN about an opportunity to reprocess uranium tails and extract the usable fuel, Rapacz said. We are in the process of getting that project under way, and it could supply CGS with fuel for four reloads, beginning as soon as 2009, he said. We have a favorable fuel contract right now and will continue to take advantage of it, Rapacz added. The cost of the uranium tails project is $88 million over two years, he reported, adding that BPA has signed a letter agreement for the project, which has gone to DOE for signature.

We are in a unique position to undertake the tails project because of our relationship to BPA as an agency of DOE, Mouncer indicated. It's an opportunity available to us alone right now, he stated.

Did BPA's risk assessment office look at this project? John Saven (NRU) asked. Yes, we did an assessment of "what could happen" and potential negative impacts, Rapacz responded. We have "an escape clause" and can cancel the project at any time, he added.

Our risk was thoroughly analyzed, since BPA will temporarily be the owner of a large amount of uranium tails, Norman said.

We anticipate financing the $88 million, Rapacz said, noting that BPA is still analyzing possible financing scenarios in the context of its total debt portfolio. We expect to see a $20 million to $30 million benefit from the project over 10 years, he stated. Whose capital would that be, BPA's or EN's? Howard Schwartz (WA) asked. We're presuming it would be EN financing, Mouncer responded.

Rapacz continued with an explanation of issues related to relicensing CGS. The current license expires in 2023, he said. Many plants in the United States have sought relicensing, and the opportunity is open to CGS, Rapacz said. The projected cost of preparing the relicensing application and going through the Nuclear Regulatory Commission (NRC) process are $14 million over three years, he said. The question is whether we include the costs now and "strike while the iron is hot" since the NRC has been approving these, Rapacz explained. Vic Parrish strongly supports this, but we don't necessarily share that view, he said. We need to consider whether we want the plant in our portfolio, but having the option may be worth it, Rapacz said. The risk people tell us we should delay the decision about having the plant in our portfolio as long as possible, he added.

Is BPA's concern based on the belief that another resource would be available or on its view of what its future role will be? Saven asked. It isn't the latter, Norman responded. It depends on the risk, he said. It seems logical to agree to the extension, but there are risks, Norman pointed out. We want to make the decision in concert with those who are affected – our customers, he stated. It's a big decision, it costs money, and we feel we should have some consultation first, Norman said. BPA's current obligation is for the life of the plant, until 2023, he clarified.

There must be a way to work this out without committing BPA "to an eternity" with the plant, Eldrige commented. The question is what you are buying with an option, Nadal commented. You are buying a license to operate another 20 years, Rapacz responded. NRC could put conditions on the renewal, he added.

One-third of the plants in the country are already relicensed, Parrish stated. As an industry, we view this as "a sweet spot" since the NRC has staff that are up to speed on the issues and are moving the applications through quickly, he said. If you wait, there could be more onerous requirements, Parrish added, noting that some of the recently relicensed plants are older than CGS. He said EN had done an analysis of relicensing and assumed it would have to put $80 million into CGS to operate another 20 years.

Would relicensing raise the level of contributions to the decommissioning fund? Kevin O'Meara (PPC) asked. Yes, it would affect a lot of things, Parrish responded. Rapacz pointed out that decisions about upgrades and maintenance would have a different context if EN is going to go for a license renewal. There are things that are obsolete and need to be replaced, but there is a difference if the decision is being made for the long haul, Parrish added.

There may be merit to spending $8.5 million in the next rate period, Kevin Clark (Seattle) commented. Can BPA work with others in the region and EN to have a process about the license extension? he asked. That is a decision for the EN Board, Norman responded. We haven't yet considered the acquisition of the power beyond the plant's current life and are committed to consultation, he indicated.

It's an easier decision if it is "an option" on the plant, Eldrige commented. I like the idea of deciding sometime in the future about keeping the plant in the BPA portfolio, he said.

Dick Helgeson (EWEB) wondered whether a new license would obligate BPA into the future or whether it would really be an option. If EN applies for the license and gets it, it doesn't mean we've made the decision, but we have the costs of going through the process and decisions later about making upgrades and replacements, he commented.

How does the decision on relicensing overlap with making upgrades to increase production by 15 percent? Steve Marshall (Snohomish PUD) asked. If you commit to continuing to run the plant, it's better to run at 1,335 MW than 1,107 MW, Parrish replied. In that case, basic economics says you should do it sooner rather than later; but it's not necessarily tied to relicensing, he said. I took the uprate off the table this rate period – it's a $150 million project and would entail a 100-day outage, Parrish added.

Schwartz pointed out that with a decision to make a large capital investment in the plant, if BPA is to acquire the output, the Northwest Power and Conservation Council could have a role. The Council would want to look at whether this is the best expenditure for the additional resource, he said.

<u>EN Presentation</u>

Parrish started his presentation, saying EN has become a better organization in understanding risk, taking smarter and more informed risk, and in looking for innovative solutions. We have an internal rule that we don't amend the budget, he said. If we have an unanticipated expense, we try everything first to absorb it, Parrish said.

He listed several recent actions EN took to support the region, including the debt optimization program (DOP). What are the benefits of DOP to the ratepayers? Eldrige asked. There are interest cost savings, and it helps with BPA's borrowing authority, Norman said. Debt optimization is not increasing our total debt, he added. But how much lower are my rates? Eldrige asked. We can get you that information, Norman said.

Parrish continued through a list of unbudgeted costs EN has faced, including increased security. We have spent $22 million on security since September 11, and we anticipate other things that will need to be addressed, he said. According to Parrish, the nuclear industry as a whole has spent $1.2 billion on security since September 11, and the requirements "have gone beyond reasonableness." He suggested those who are paying the bills should send letters to legislators seeking more consideration of what is reasonable in terms of security. We went from 65 security people before September 11 to 138 now, and we are carrying an additional $7 million in expense forward every year, plus escalation, Parrish reported. "We need your help to stem the tide," he stated.

The nuclear industry has communicated with NRC about this, but the people making the decisions are people elected to office, Parrish said. "We have people on the East Coast making decisions for guys out in the desert," he pointed out.

State energy offices have been dragged into the security issues, and "we have found a rigid mindset" among federal officials, Schwartz said. The only way to change this is to have our elected officials "call time out," Parrish agreed. The NRC is more aggressive about security than the Department of Homeland Security, he said, relating industry experience with the NRC coming to plants to test security systems for threats beyond which they required the plant to prepare.

Parrish said CGS has generated more power than BPA forecast in almost every year, and in 2004, it recorded the largest amount of generation ever, with over 9,000 gigawatt-hours. Six plants in the country are stand-alone plants, and he reiterated Rapacz's statement that CGS has about a 15 percent cost penalty because it does not have the economies of scale provided with fleet operations.

Parrish explained a number of factors that are driving costs upward, including regulatory and waste disposal costs. Have you looked at ways you might join a fleet operation? Paul Elias (McMinnville) asked. Parrish said EN has explored linking up with other operators. The Board supports the idea, but nothing has come so far of talks with other nuclear operators, including Nebraska Public Power, he reported.

Parrish compared CGS operations and FTE to industry benchmarks and said the plant, which has more staff than its peers, will see FTE reductions. We are shooting for between 974 and 985 total, he said. Our aim is to continue to benchmark and go with what's best for the plant, Parrish said.

Could you contrast your efforts today with what you did in the 1990s to cut costs? Frank Lambe (Emerald) asked. We went too far with cutbacks in the 1990s, Parrish responded. He recapped CGS' generating history, the rolling average cost of power, which is about $27 per MW in 2004-2005, and direct and indirect FTE.

Mouncer explained EN's budget planning cycle and its budget objectives, which include staff reductions and reducing non-labor costs by 10 percent. Our forecast for O&M in 2006 is $199.5 million, he said.

Your objective of being in the top 50 percent of plants doesn't sound like the right message, Kevin Owens (Columbia River PUD) said. I don't think you have characterized it correctly – this isn't sending the right message, he said when Parrish explained that CGS has to walk a fine line between being cost effective and providing reliable operations.

Where do you stand with the NRC? Eldrige asked. We are in "column one," which indicates NRC is confident in our ability to operate and fix any problems, Parrish said.

Somewhere in this decision we have to look at all the costs, including debt service, Eldrige said. The cost isn't $26 per MWh, he said. I'd encourage BPA to be clear about what the total costs are, so we can make clear decisions, he stated. The debt costs are sunk, and there is not much we can do about them, Norman responded. But going forward, there are capital decisions, he added. The nuclear plant ought to be presented in the same way as the hydro system – we need the whole picture, Eldrige said. We can only avoid the O&M, and we don't want to create confusion about what the avoided costs would be if we didn't operate the plant, Norman said. I think there is more danger of misleading if the debt information is left out, Eldrige said.

Do you think this is a well-run plant? Eldrige asked. We're in the middle of the pack in terms of operations, Parrish responded. The question ahead is whether the nuclear plant can compete with other options, Eldrige said. So the right comparison is what can we do relative to the nuclear plant O&M, Norman commented.

Mouncer outlined budget reductions for 2006, and Parrish said he had to cut another $13 million to get to the numbers presented. How confident are you this will happen? Eldrige asked. Absolutely, it will, Parrish responded. Mouncer continued with the costs within various categories of the budget, and he noted that EN continues to pay a significant disposal fee, $9 million in 2006, despite the fact that DOE is "woefully late" in opening the Yucca Mountain facility. We have sued DOE for breach of contract and will try to recover costs we've incurred in having to develop on-site storage, Mouncer explained.

He outlined the activity based management approach EN uses, saying it is uniform across the industry and helps operators get a good view of costs and make decisions about cost cutting. Parrish noted that one decision EN is contemplating is whether to invest in technology that would move fuel quicker and shorten refueling outages. Parrish also said EN has an accredited training program and operators spend one week in every six in training.

Ralph Cavanagh (NRDC) asked if there is adequate capacity in the on-site spent fuel storage facility to meet EN's needs. It is set up such that we can add capacity as we go, Parrish responded.

Mouncer completed the 2006 budget explanation, noting the priorities in the baseline budget, and Parrish went over the long-range plan for 2006-2011, including CGS initiatives, assumptions, and costs. The numbers show a commitment on our part to keeping everything as constant as possible, he said.

We've seen a significant increase, $70 million, in CGS costs from the figures we saw in the opening workshop, Kris Mikkelson (Inland) pointed out. We have to update the original table to reflect EN's new numbers, Norman acknowledged. We did not have them for the opening workshop, he added.

Parrish continued with the budget projections for 2006-2011. We are presenting our budget to the Executive Board this month and expect to get final approval in April, he said. With regard to staffing, Helgeson asked about the use of contractors in addition to FTE. We do hire contractors to supplement the staff, but we are reducing the numbers, Mouncer responded. We hire contractors, but as a matter of policy, we don't like to do it, he added.

Parrish explained what plant modifications and major maintenance entails, and he noted there are incremental costs associated with a refueling outage. He listed the major projects anticipated in the 2007 outage year, which total $53.9 million. Parrish said CGS is captive to some vendors in the nuclear industry, and there have been times when costs were reduced by pursuing a reverse-engineering solution. He said the costs for some services are on "a value of service" basis rather than the cost of providing the service. If a service will increase generation, the providers "want a piece of the pie," Parrish pointed out. The list on page 88, security, fire protection, spent fuel pool cooling, transformers, power uprate, and new facilities are not included in the long-range plan, he noted.

The figures on page 75 are our bottom line, Parrish wrapped up. This is our best effort and the best input we can make to the process, he said.

Rapacz recapped where PBL has projected CGS costs in the next rate period. It seems we have an issue with the timeline, Marshall said. EN will continue to make cuts, so can't we wait until next year at this time to set the costs for the rate case? he asked. We'll put new numbers in for the final rates and reflect their progress, Norman responded. We have staff in Richland who work with EN to be sure BPA is comfortable with the costs, he added. Vic and his staff have taken an aggressive approach to cost cuts, and they are getting to where we think the target should be, Norman stated.

You should assume more output based on CGS' recent performance, Clark advised. Use the EN assumptions – yours is flat and theirs is going up, he pointed out.

Use a budget number that will keep rates flat and then see what else it will take to get down to 27 mills, Eldrige suggested. We want to know what it will take to get to 27; is it possible? he asked. We need to have a separate discussion about the 27 mills, Norman responded.

Schwartz asked about forecasting the borrowing to pay for capital items. It's an EN Board choice, but if BPA customers said to capitalize something rather than pay out of revenues, they would listen, Norman responded. I'm encouraged by your orientation to cost management – it feels really different than other parts of the budget, Helgeson said.

III. Corps and Reclamation O&M

We heard at the Sounding Board there is interest in having regular meetings with the FCRPS partners, Mark Jones (BPA) said. We like the idea, and would like to offer to start doing that, he said. We could also set up visits to the plants to see and discuss how they are managed, and for you to see specific projects that are being worked on, so that offer is open too, Jones said.

He began by clarifying questions that arose at the technical session about the forced outage factor. First, it is a lagging indicator, and we don't want to wait until a unit goes down before we address a problem, Jones explained. Also with regard to contractor levels at the Corps, they do not have contractors working in lieu of FTE, he said. There are contractors associated with specific jobs, but there is no large number of contractors who work on an ongoing basis, Jones said.

We're talking about a system here that generates 9,000 aMW, has a 22,000 MW capacity, and is operated with 1,601 employees, Cavanagh pointed out.

There was also an issue raised about the Integrated Business Management Model and why we started with resource planning, Jones continued. We realize that isn't typically the starting point, but it's where we were when the asset management strategy was developed, he clarified. So in this process, that is where we started, Jones said.

O&M Expense

Mike Alder (BPA) began his presentation by noting that O&M at the Corps and Reclamation projects includes fish and wildlife (F&W) O&M and cultural resources. He pointed out that Reclamation plants are at a baseline to maintain reliability and unit availability, but there are issues to deal with on the Corps side. The FCRPS agencies are continually benchmarking themselves against other hydro operators, Alder continued. Of the six indicators, we are in summary at or below industry cost on five, he noted.

We have examples of what we are doing to improve O&M cost-effectiveness, Alder said, going over the staff reductions at Reclamation projects. He explained the use of "multi-crafting" that combines the main mechanical crafts into a single staff position to accomplish maintenance more cost-effectively.

Dave Murillo (Reclamation) described "the cultural change" that has gone on at Reclamation projects in the Yakama Basin to break down "territorial" approaches to O&M and encourage people to assist each other across functions. Some of the changes required overcoming union objections, he acknowledged. But we told people we had to come up with the right number of FTE at a project, Murillo said.

Jim Mahar (Corps) said dollars are being saved at the Bonneville project with “smarter maintenance,” and he pointed out that “attitude” and a maintenance management system called FEMS/MAXIMO are making a big difference. He noted that some positions are now filled for a specific term, during which a skill is needed. Staff is being mixed from one hydro project to another, and people with needed skills are borrowed when possible, Mahar said. The Corps is also being innovative and saving dollars by using crew foremen to do training, rather than hiring outside trainers, he continued. We’re swapping inventory between plants, and the attitude is changing on how we can save money, Mahar reported.

Mark Jenson (Corps) pointed out that at Chief Joseph Dam staff did an in-house installation of the new automatic control system. We hired power plant trainees and did the installation ourselves – we achieved the results and trained new craft workers at the same time, he said. We are using creativity and innovation to save dollars, Jenson reiterated.

Alder listed opportunities for efficiencies and reductions, pointing out that the FCRPS agencies expect to see savings as a result of them.

I applaud you, and I understand what you are saying about cultural change, Eldrige said. Do your operations people really care about what things cost? he asked. Our operations people ask whether anyone notices the difference and the sacrifices they are making – they do care, and the staff is coming up with even more ideas, Murillo said.

Eldrige gave an example of inefficiency he had seen, noting that several agencies sent people out to check the same screens at an irrigation diversion. It sounds like a lack of coordination, Murillo acknowledged. We try, but people sometimes forget, he said.

Pete Gibson (Corps) pointed out the agency heads at the Corps and Reclamation signed an agreement that allows for sharing and being more efficient at FCRPS O&M. From the corporate level down, these two agencies understand the need, he said. Culture is difficult to change, and the leadership comes from management, Mahar added.

You point out that it’s valuable to get more generation from the system, but for the irrigation savings, we’ve heard $20 per MW not the $35 on page 13, Cavanagh said. We should be consistent, he stated. Some of the irrigation districts are updating their pumps, and the Columbia Basin irrigators are looking at ways to be more efficient, Terry Kent (Reclamation) responded.

There are front-end costs associated with irrigation modernization programs, and there are few incentives to improve efficiency, John Saven (NRU) pointed out. We need incentives for both water and energy use, he said. Are there other programs through which we can make money available to the end-use customers? Saven asked.

Rick Lovely (Grays Harbor) asked if the drawdown schedule at Grand Coulee for a headgate repair could be revisited. Could it be shifted to this fall? he asked. We're very concerned about the drafting with no chance for refill, Lovely stated.

We have maintenance and security concerns to consider, but I'll take that comment back, Kent stated.

Most good ideas come from the field, Clark pointed out. We can't afford any more increases in maintenance, and I'd propose a gain-sharing program, he said. We can't fund the proposed level of increase in 2007-2009, but if we fund part of it, could you institute a program that rewards plants for every dollar saved? For a dollar saved, they get $2 for projects they choose at the plant, Clark suggested. Put some of the proposed activities on a gain-share basis, he urged.

Alder explained the proposed increase for non-routine extraordinary maintenance. We've looked at this and found the resources required are as much as $18 million annually, but we're proposing $8 million to keep the hydro projects at baseline reliability, he said. The McNary headgates are among the extraordinary needs – they're 50 years old and "we've tried to band aid the situation," Alder said. "It's a huge expense," but we lose $8.6 million in an average water year, he pointed out. A repair needed on a generator at Chief Joseph is another example of revenues being lost due to extraordinary maintenance needs, Alder explained.

Why can't you capitalize these expenses? Lambe asked. They're considered O&M – it's not a replacement or an upgrade, Alder responded. Couldn't you set up a contingent financing fund? Marshall asked. Why not try to save money in the good hydro years to set up a fund to do extraordinary maintenance, he suggested.

Clark raised the issue of the forced outage factor and whether it tracks with the investments. It's a lagging indicator, Alder responded. The forced outage rate has come down, and it is at a good level, Gibson added. We are not proposing to deviate from existing O&M, but are proposing new work that if it isn't funded now, the maintenance level will drop and the forced outage factor will go up, he explained. We are getting close to a baseline level of work, Gibson said. We see you proposing a $50 million increase over four years, Clark responded.

Couldn't you address the situation at Chief Joseph now? Helgeson asked. It is costing you money, he added. I had "a hopeful thought" that maybe you could amend the budget to address a situation like this, Helgeson said. We have extraordinary maintenance projects going on now, but we're constrained in our funding to address all the needs, Alder replied. But we can change budgets if needed, he clarified.

We have $6 million to $7 million in critical work we could do in 2005 if we had funding, Gibson said. We have “a hopper” of extraordinary maintenance that is needed, he added.

If the question is money, at some point we need “to tee up” the issue of the relationship of one FCRPS activity to these others – the revenue from summer spill could pay for some of these, Saven said. I would like us to describe other alternatives for where the money for these projects could come from, he said.

Do you do a cost-benefit study on these actions? Lovely asked. We do an energy benefits analysis that shows us the difference between doing something or not, Phil Thor (BPA) responded. The $242 million per year for the next rate period gets you the benefit we’ve depicted on this graph, he said, referring to page 36.

Is there flexibility to respond to outages and generators going out? Lambe asked. Yes, we don’t leave units out of service, Thor said. We always address forced outages, but we plan strategically about when to repair them, he added.

We look at every forced outage and analyze the revenue effects, Alder said. There is no denying that program costs have gone up, but $55 million of that is labor-related and due to things tied to inflation, he said. Asked about the FTE forecast, Alder said he did not expect it to go up for either Reclamation or the Corps. He explained the drivers of change on page 12, including NERC/WECC requirements. Jones noted that the East Coast blackout increased sensitivity to reliability requirements, and since generators support the transmission system, there is pressure for the FCRPS to get into compliance, he said.

In dealing with risk, could you identify the non-essential things, and if there are funds, fund them, but if not, don’t, Marshall suggested. Incorporate this approach into risk management – some things may not be essential now, but will be essential later, he said.

Gibson indicated the program is still evolving. We are seeking a business model with planning and a strategy to support decisions, he said. Let us finish this concept and then we’ll have a cost-effective way to make decisions, Gibson urged.

I’m suggesting that you prioritize things that you can put off – it will help with risk management, Marshall responded. And think in terms of a flexible strategy, so in wet years you can do maintenance, Clark added.

I’d like to push back on the idea of a hard cap on O&M, Cavanagh said. One of the most important things on the system has no internal rate of return (IRR) – you can’t measure it in terms of dollars and cents, he said. There should be some projects that you just do without crowding anything else out, Cavanagh said.

“We ought to be ashamed” that we have gotten to this point with some equipment in the system, Eldrige commented. We’ve let things go downhill too far, he stated.

Alder pointed out that environmental compliance poses a risk of increased costs. Does this budget cover the Updated Proposed Action? Saven asked. To the best we can estimate, it does, Alder responded. He turned to page 17, a table of the effect the O&M program has had on rates. Without the program, we'd have the equivalent of seven of 209 units out of service, Alder said. You make a reasonable case on the first two lines, the rest is too speculative, Eldrige commented, referring to the calculation of lost revenue if the O&M program had not increased.

The value of the O&M program shows up in annual revenue, Alder said. The extraordinary maintenance is a real issue for us, he summed up.

You need to correlate page 10, average program cost, with the forced outage factor graph on page 56, Clark stated.

Capital Program

The capital management program makes investments to meet the two objectives of the asset management strategy, Thor said: increased generation reliability and increased generation efficiency. The reliability investments involve spending to upgrade, replace, and refurbish equipment, and the efficiency investments aim "to squeeze the factory harder," leading to increased generation, he explained.

Thor pointed out where the FCRPS stands on five cost benchmarks comparing it to other hydro operators, noting the system is well below its peers on four of the five. As our program ramps up, we will get closer to the benchmark in these areas, he said.

According to Thor, BPA plans to invest $516.3 million from 2002 to 2006. Direct funding is the mechanism for achieving improvements at Corps and Reclamation projects, and all but $4 million of the dollars budgeted for the period are committed, he said, going through the budget on page 35. "We are in the hole for 2006," but it's netted out by the leftover from 2005, Thor explained. We can reprogram funds if needed – we do it all the time, he said.

Thor explained that one of the criteria for projects is the IRR. For things that affect reliability, the threshold is 13 percent, he said. But for efficiency improvements, we run the IRR and target things that get us the most, Thor said. The chart on page 36 is what we postulate would have happened since 1998 without the capital investment program, a steady decline in average MW of generation and revenue, he indicated.

The net present value of the program from 2005 to 2023 is shown on page 41, Thor continued. The IRR for the program as a whole is 29 percent, with 22 percent for generation reliability and 150 percent for generation efficiency improvements, he explained. Most of the efficiency gains are associated with turbine runner replacements, and "you can't do these projects overnight," Thor said. He went through the graphs on forced outage factor, with and without the capital program; explained the McNary turbine runner replacement project; and the effect the capital program has had on rates.

Will the increased output at McNary be factored into the generation forecast? Randy Gregg (Benton PUD) asked. It's out there in time a ways, so no, Thor responded.

Thor explained "a thought exercise" about the cost for a sustained equipment replacement program for the FCRPS. We would need to invest about $110 million a year to keep the system reliable, he said. In terms of the appropriate level for 2007-2009, Thor said benchmarking, forced outage factor, and the rate effect suggest we're proposing the right budget. We have the ability to invest at the proposed levels, and we have to be strategic with our investments, he said. We have a hopper of capital investment projects identified, and the sum is greater than what we are showing here, Thor wrapped up.

To manage the costs down, we need to look at opportunities to avoid revenue loss and opportunities to increase generating revenues, and identify projects that can be postponed, Schwartz commented.

Thor presented "the wish list" of projects identified by the hydro project managers. We can't meet all of these needs, so we will have to prioritize, he said. With efficiency gains, about the only choice we have, in addition to the optimization effort, is turbine runners, Thor explained, noting there are hydro plants in line for replacements.

I'd be interested in the following, Saven said: whether this document covers the proposed actions for BiOp implementation and how that compares to "a reference operation." We should be aware of what BPA may have to do, he stated. I'd also like to see the difference in effect of a 3 percent versus a 4 percent rate of inflation and an estimate of the value of eliminating summer spill, Saven said. "What size pot would that make available for extraordinary maintenance?" he asked.

Let's put the irrigation water back in the system and see the impact of that, Cavanagh suggested.

Eldrige made the following suggestions: take the conservation and renewables budget and put it into the hydro system, which is "the quintessential renewable resource"; and show what it would look like to ramp up to the $249 million O&M budget on a straight line. He also said he liked the idea of a fund for extraordinary maintenance and asked whether BPA is the only source of funds for the O&M program. Why can't there be appropriations for some of this? Eldrige asked.

I have concerns about the escalation in the O&M budget, and it's an area to focus on, Helgeson said. Regarding capital, "I couldn't connect the dots" to get to the increasing budget, he said. The most compelling information is on page 42, which spoke to meeting the equipment costs over time, Helgeson said. As for the budget on page 35, I'd like more information on what drives the efficacy of the investments, he said.

The investment level of $110 is good documentation, Clark said. With this level of spending, we would continue to see an investment in "the engine that makes the revenue," he said. We need to get a handle on O&M spending – instead of escalating O&M, we need to find a sustainable level that customers can stick with, Clark said. We have to hold the line on O&M spending, he reiterated.

I'd echo the sentiments on O&M spending, Mikkelson stated. We need to know what we are trying to achieve with increased O&M, she said. The information on capital investment to maintain the integrity of the system speaks to the need to develop a major maintenance program that goes year to year, Mikkelson said. I am concerned about system degradation unless you dedicate funds to major maintenance and do it systematically, she added. What incentives are in place for cost effectiveness and to assure that the right projects are rising to the top? Mikkelson asked.

CGS O&M will cost $284 million a year, and O&M on the entire hydro system is $242 million – that's 1,100 MW of capacity compared to 22,000 MW, Cavanagh pointed out. Is there any doubt "we were grotesquely under-investing in the hydro system"? he asked. The real emphasis should be on finding more cost-effective investments, Cavanagh stated. Think about the order of magnitude between CGS and the hydro system, he urged.

I want BPA to take money that is being directed elsewhere and direct it to this, Eldrige stated.

The hydro system is our cheapest resource, but we still have to control costs, Marshall responded. We're struggling to get rates down, and our customers expect to see a reduction, he said.

We have a list of more information we need to get you – I can't promise you about when we'll get back with it, but "we will close the loop," Norman stated.

The meeting adjourned at 3:50 p.m.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on an ongoing basis. The Web address is www.bpa.gov/power/review.

Columbia Generating Station/Energy Northwest

1. What are the benefits of DOP to the ratepayers? How much does it lower rates?

2. What opportunities will be provided for customer input on the decision on CGS license extension?

3. What is the all-in cost of CGS, including debt service?

Corps of Engineers/Bureau of Reclamation

4. There are front-end costs associated with irrigation modernization programs, and there are few incentives to improve efficiency. Are there other programs through which we can make money available to the end-use customers?

5. Can the drawdown schedule at Grand Coulee for a headgate repair could be revisited. Could it be shifted to this fall?

6. What are the alternative sources where money for these projects could come from?

7. Please correlate page 10, average program cost, with the forced outage factor graph on page 56.

8. Does the presented information cover the proposed actions for BiOp implementation and how that compares to "a reference operation?"

9. How much lower would this budget be if it were inflated at a 3 percent rate starting with 2003 actuals?

10. What is the estimated cost of spill this year?

11. What would the effect be of capitalizing federal FTE costs?

12. For the budget on page 35, provide more information on what drives the efficacy of the investments.

13. How many contract employees do the Corps and Bureau have (i.e. those who function like full time FTE, not short-term contractors)?

PFR- 009
APR 01 2005

Kuehn,Ginny - DM

From: clint lougheed [lougheed@bossig.com]
Sent: Friday, April 01, 2005 11:25 AM
To: BPA Public Involvement
Subject: Efficiency Investments

I urge Bonneville to significantly increase its investment in energy efficiency beginning in 2006. Bonneville's planned annual acquisition of 56 aMWs at an annual cap of $80 million is insufficient to avoid acquiring more costly and more environmentally destructive sources of power. Energy efficiency is the cheapest, most abundant and most environmentally benign source of power available to Bonneville. Bonneville needs to dramatically increase its efficiency acquistion and should plan on investing $125 million to $150 million annually for energy efficiency with the goal of acquiring 70 to 80 aMW annually beginning in 2006. Energy efficiency pays for itself and is the best investment Bonneville can make to meet future load growth. Efficiency also reduces consumers electric bills and can help improve the economy of the Northwest. I strongly recommend Bonneville increase its investment in energy efficiency.

Clint Lougheed
PO Box 1043
Leavenworth, WA 98826
509-548-6441
lougheed@bossig.com

PFR-010
APR 05 2005

Kuehn,Ginny - DM

From: Pete Peterson [Pete.Peterson@pgn.com]

Sent: Monday, April 04, 2005 8:54 AM

To: BPA Public Involvement

Cc: greggr@bentonpud.org; Manary,Michelle L - PFF; Scott.Brattebo@PacifiCorp.com; ghcarr@pacifier.com; Lyn Williams; achalier@ppcpdx.org; michellep@ppcpdx.org; lsjordan@snopud.com

Subject: PFR Comments - Energy Northwest

Thanks for the excellent workshop on the Columbia Generating station. Please see attached for our follow-up questions.

Regards,
Pete Peterson
Joint Customer CGS Taskforce Leader

3-31-05

Follow-up Questions on the Columbia Generating Station (CGS)

1. General – The CGS revenue requirements can and should be substantially reduced to reflect the revised (March 2005) estimates and reductions due to debt financing of capital projects that were discussed at the March 15th workshop. Please identify any changes made since the March 15th workshop numbers (see below comments), and provide the revised average FY07-09 revenue requirement for CGS O&M.
2. BPA Presentation slides 5 and 19 - has the March 2005 estimate been reviewed and/or approved by the EN Board? What, if any, changes were made?
3. It was reported during the workshop that debt financing of capital projects could be as much as $34 million in FY07, $12 million in FY08, and $14 million in FY 09 (Ref: page 1 of 13 of the March 15th workshop notes). As noted on page 6 of 13 of the March 15th workshop notes, June is the target to have new numbers on the capitalization decisions. How will BPA ensure that the resulting reduction in FY07-09 expenses will be included in the final CGS revenue requirement? Will the BPA customers have an opportunity to review and comment on the revised numbers, since this is beyond the scheduled PFR comment deadline?
4. What are the proposed criteria and guidelines for the new capitalization policy (Ref: bottom of page 4 of 13 of the March 15th workshop notes)?
5. EN Presentation Slide 12 – What is the actual CGS avg. O&M average for the 1997 – 2000 time period?
6. EN Presentation slides 25 and 79 - What is CGS's current total annual payroll, and what will the reduction be as a result of the proposed staffing reductions between FY 05 and 06?
7. EN Presentation slide 74 – What have the planned and actual CGS refueling outage durations been for the past four refuelings?
8. EN Presentation slide 77 and BPA Presentation slides 18 and 19 – Please explain in more detail the difference in FY 07 – 09 costs between the EN Presentation slide and the BPA Presentation slides.

PFR-011
APR 11 2005

Kuehn,Ginny - DM

From: getfit@getenergized.com
Sent: Tuesday, April 05, 2005 12:52 PM
To: BPA Public Involvement
Subject: Comment on Power Function Review

Comment on **Power Function Review**
View open comment periods on http://www.bpa.gov/comment

Pavel Goberman
Have a Brain
getfit@getenergized.com
(503)643-8348
P.O. Box 1664
Beaverton OR 97075
Sea Lions, theirs enemies are sharks, so, it is simple: make a few manekens of sharks, moving on the cable across river. Pavel Goberman - Candidate for Director Beav. School District and US Rerresentative. P.O. Box 1664, Beaverton, OR 97075 (503)643-8348 www.getenergized.com/vote.html

PFR-012
APR 11 2005

Kuehn,Ginny - DM

From: Bittick [bittick@icehouse.net]

Sent: Thursday, April 07, 2005 6:25 PM

To: BPA Public Involvement

Subject: aluminum co.subsidizing

Is it the responsibility of the public consumers of bpa to subsidize a private enterprise, e.g., the aluminum companies? The problem of managing revenue is theirs, not ours. Please don't ask the general public to pay for, through increased power rates, the mismanagement or mistakes made by any private company - especially the aluminum corporations.

Thank you,

Frank and Charlene Bittick
208-666-0406

PFR-013
APR 11 2005

Benton R E A
The Cooperative Way!

BENTON RURAL ELECTRIC ASSOCIATION

402 7TH Street ◈ P.O. BOX 1150 ◈ PROSSER, WASHINGTON 99350 ◈ 509/786-2913 ◈ Fax: 509/786-0291

April 5, 2005

Steve Wright, BPA Administrator
Bonneville Power Administration
PO Box 3621
Portland OR 97208

Dear Mr. Wright:

Subject: BPA Fish and Wildlife Expenditures

As a regional decision maker, we urge your support in reigning in the unprecedented spending of ratepayer dollars on BPA fish and wildlife program funding.

We have recently participated in a BPA Public Review Meeting entitled Fish and Wildlife Costs Proposal for 2007 Power Rate Case. We appreciated the opportunity to receive information regarding the proposed fish and wildlife costs for the 2007-2009 period.

We were quite surprised to find that current BPA fish and wildlife costs run nearly $700 million per year for either direct programs or in foregone revenues tied to the curtailment of power generation. At this rate, the fish and wildlife costs make up almost 18% of BPA's total power business line costs, and exceed the total annual costs associated with the BPA transmission system. We were further surprised that there is another $350 million of BPA financial obligations that are backlogged for fish and wildlife studies performed by the Corp of Engineers.

We remember the BPA promise of two cents in 2000, and BPA's commitment that Federal Base System energy could be provided to the Direct Service Companies and IOUs without costing preference customers any more. With BPA's current priority firm power rate at roughly $32/MWh, or more than 50% higher than the BPA wholesale power costs in 2002, many of our local businesses are struggling financially. We have lost faith in BPA's ability to control costs, and to balance the impact of many stakeholder costs.

This lack of faith in BPA is further exacerbated when we understand that BPA is looking at trying to absorb another $139 to $325 million per year for Sub-basin fish and wildlife enhancement. These costs, combined with the costs that are already in place, would bring the total annual cost of fish and wildlife programs to $1 billion per year. We find this situation unacceptable!!!!

When we calculate the impact of fish and wildlife costs on a per customer basis for our utility, we are amazed to find that each consumer on average pays almost $20 per month for these programs.

In addition to our concerns regarding the level of BPA responsibility for fish and wildlife funding, we are also concerned about the devastation caused by, tribes and others who are catching upwards of 32% of all returning Snake River fall Chinook ESU salmon in the Columbia River between Bonneville and McNary dams. If our goal is to protect and enhance fish and wildlife, how can such significant catch numbers be permissible?

It is time for regional decision makers to step up and protect the only financial stakeholder in the region-**the ratepayer**. We must put a stop to the exorbitant fish and wildlife program spending levels that are significantly contributing to the destruction of the northwest economy.

Sincerely yours,

Virgil Boyle

Virgil Boyle
President of the Board

Bonneville Power Administration
Power Function Review Management Level Discussion
March 17, 2005

Rates Hearing Room, BPA Headquarters, Portland, Oregon
Approximate Attendance: 40

Internal Operations Costs Charged to Power; Debt Service

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

I. Introduction

Paul Norman (BPA) welcomed the participants and asked for any comments on the scoresheet handed out the day before. We will continually update the sheet to reflect new ideas and changes relative to the program numbers presented in the opening workshop, he said. This is where we'll track ideas to keep costs down, so it's important to get your reactions, Norman said. There were head nods around the group and comments that the sheet was helpful and a good idea.

Norman also double-checked that the decisions forum handout is clear. This tells you where the action is on various topics and where decisions will be made about costs that go into the rate case, he clarified.

In a question related to the previous day's topic, Steve Eldrige (Umatilla) asked how dollars are treated if, for example, the Corps accomplishes its list of O&M projects for less money than is budgeted. If they underrun the budget, the money ends up in our reserves, Norman said. David Steele (BPA) said there is an arrangement with direct funding that allows the Corps to spend half of any underrun on another project. Eldridge recounted a suggestion from the previous day that BPA consider letting the Corps and Reclamation build their own reserve fund in good hydro years – money that could be used for future O&M.

Frank Lambe (Emerald) said he wanted to be clear that he didn't think the increases for Corps and Reclamation O&M are warranted. They should hold the line, he stated.

II. Internal Operations Charged to Power

Steele began his presentation by pointing out that the internal operations costs charged to power are projected to be $116 million annually in 2007-2009, about 5 percent of the power budget. He stated the internal operations objectives for the PFR: power rates reflect lowest practical costs to meet BPA's objectives and discuss opportunities for further cost reductions and actions that are currently being taken.

Steele went over historic costs and pointed out that the projection for the next rate period is 8 percent higher than in 2002-2006. The internal operations costs are primarily employee compensation and related expenses – they make up 77 percent of the budget, he said. In addition there are costs for service contracts and "other," which includes training, materials, rents, and miscellaneous, Steele explained. The risks for increased costs include new industry requirements, and demands from customers, constituents, and stakeholders, he said, but there are also opportunities for reductions, including the Enterprise Process Improvement Project (EPIP), voluntary separations and early retirements, and an initiative to reduce the overall grade structure of BPA employees.

When will the numbers from various savings efforts be factored in? Kevin O'Meara (PPC) asked. We hope to have some in the closeout letter on the PFR, Steele responded.

The early outs and retirements give you an opportunity to look at the organization and consider new ways to staff, Paul Elias (McMinnville) stated. You may decide not to refill all of the positions – it's a big opportunity to make cuts with less employee impact, he pointed out. I'd suggest you go into it by targeting jobs and positions, not necessarily targeting people, Elias said. Don't let momentum from the past propel you into filling the same jobs, he advised.

We are looking for opportunities to get the work done with fewer people, and we are considering which positions we need to refill and which we don't, Norman stated. We are trying to do just that, he said of Elias' suggestion.

Kevin Clark (Seattle) asked about the summary table on page 26. These are audited actuals through 2004 and forecasts for 2005-2009, Steele responded. Last summer, we transferred about $12 million in costs with the consolidation of our IT function; when you adjust for IT, the budget is about equal to previous years, he said.

Why the dramatic increase from 2005-2009? Rick Lovely (Grays Harbor PUD) asked. "People costs" drive the escalation – cost of living increases, health care, and changes to the 401(k) plans, Steele replied. We have forecast a 3 percent increase going forward, he added. The intervening years 2004-2006 are also growing fast, Randy Gregg (Benton PUD) pointed out.

Steele explained where the internal operations charged to power show up in BPA's financial statements and the Customer Collaborative reports, and he went through a list of accomplishments. From 2007-2009, adjusting for the IT consolidation, we're keeping costs at 2001 levels, and we've held the line on inflation for eight years, Steele said. Cost cutting ideas came from the Financial Choices and Sounding Board processes, and new ones will come from the PFR, he said. Steele pointed out that PBL eliminated contingency budgets within programs – not large by themselves, but in the aggregate, "they added up," – and now there is a contingency budget only at the senior vice president level, and there are clear principles about how it can be used.

He listed the drivers of change and things that pose risk for increased costs, along with several opportunities for reductions, which include cuts in programs targeted for EPIP reviews. Asked about the staff reductions reflected on the graph on page 24, Steele said there were contractor cuts, the risk group was consolidated, and "the big one" was the IT reorganization. Since 2002, overall PBL FTE is down 7 percent – there are fewer account executives, fewer billing people, fewer support staff, Norman said.

Does BPA have a corporate plan to manage staff? Eldrige asked. We want to get to below 3,000, Ruth Bennett (BPA) stated. We look at each function and are doing an assessment of where we think the reductions ought to be – we know there are efficiencies to be gained, she added. Eldrige suggested BPA ought to consider reducing staff to save money and identify functions "BPA should not do." Also, you should adjust salaries to better reflect the type of work that is being done, he said.

We have a responsibility to be efficient and deliver value to the region, Bennett responded. That responsibility guides us, she said. We've had independent assessments that point us toward efficiencies, Bennett added.

What is driving you on the grade realignment? Kevin Owens (Columbia River PUD) asked. Over a five-year period, when competition in power markets was growing, the number of employees at Grades 13-15 doubled at BPA, Bennett explained. We were competing to get good employees, and BPA managers were offering these higher grades, she explained. There has not been a specific analysis, but intuitively, I knew we had doubled the numbers in those grades, and "we did not need to," Bennett stated. We didn't need to have a formal assessment to realize we weren't managing positions well, she said. The challenge to reduce overall grade level was not made on the basis of an analysis, we just needed to do it, Bennett reiterated.

She also pointed out that it was not management that "burgeoned" during the five-year period, it was technical and professional positions. We have technical folks at these higher grades, Bennett explained. One result is, there isn't much incentive to be a manager anymore at BPA – it doesn't lead to a higher grade or higher pay, she noted.

It is hard to see an example being set in corporate with providing information or controlling spending, Clark stated. "Your information simply shows growth and spending," he said.

Our goal is to provide a good product at an efficient cost, Bennett responded. The corporate costs that go into rates reflect costs agency wide, not just those of a single business line, she indicated. It is an agency-wide challenge to deliver a quality product at the lowest cost, Bennett stated.

At our utility, we have a lower number of FTE than in 2000, Lovely said. Why isn't BPA driving to lower employee counts? he asked.

Could you still recruit at the lower grade classifications? Lambe asked. Bennett said 550 BPA employees are currently eligible to retire and 1,000 will be eligible in the next couple years. We will have to recruit to fill positions – "we anticipate a big sea change" at BPA, she stated. Our attrition rate is very low – we are not having people leave nor are we having trouble getting people to work here," Bennett said.

Turning to her formal presentation, she said the costs being addressed are half of the $116 million for internal operations charged to power. Bennett explained what is captured in specific functions and pointed out that reorganizations have changed where things sit within the agency's structure. IT was formerly disbursed throughout the agency, and it was a big change to bring it all into corporate, she said. We have heard that people are happy having financial management located within the business lines, rather than centralized, Bennett added.

IT is a good example of why we may do more consolidations, she continued. It helps us "in getting our arms around the dollars and FTE," Bennett stated. Once we consolidated, we found we had an overall budget of $100 million annually and 500 people working in IT, she acknowledged, and "that's a lot of folks." While not all of them are BPA FTE, we basically have 500 people who are functioning like BPA employees, Bennett said. When we benchmarked ourselves, we found we are not within the benchmarks for similar organizations in the nation, she said. This is "one of the most spectacular areas" in terms of where we can seek efficiencies, Bennett stated.

She pointed out functions on the organizational chart that are undergoing EPIP review. Our financial office does "direction-of-effort" studies to determine where corporate functions should be charged – to TBL, PBL, or corporate – we have to have a rationale for charging things the way we do, Bennett explained.

Asked about the number of contractors, she said it is difficult to tally up contractors, but one way is to count by badges (to enter the building) and workstations. It's important to agree on a mechanism to count contractors, so you know how many FTE it takes to deliver the service, Eldrige commented.

The one thing we should emphasize is that "the people who occupy the top boxes at BPA are grotesquely underpaid" compared to other comparable organizations, Ralph Cavanagh (NRDC) said. "Stewardship" is a big element at BPA versus other organizations, and that is why you can recruit to organizations like BPA, he said. It's an underappreciated aspect of why people work here, he said.

We understand that, but it's true of all of public power – it's generic to the industry, Lovely responded.

Bennett explained changes to historical FTE numbers (page 14), noting consolidations and the assignment of the procurement function to TBL. Overall, "corporate FTE is coming down, and we will come down more," she said.

From 2000-2002, there was an increase, Clark said. You are up since the base in 2000, which is the most relevant base year, he said. I can't track all movements by the numbers up and down in business lines, but as an agency, we are coming down – the number of people in all three organizations is coming down, Bennett stated.

John Saven (NRU) suggested putting FTE numbers on the organization chart on page 13.

The large transmission infrastructure project in TBL brought more people into the organization, Bennett explained. In addition to more TBL staff, we had recruiting, IT, and other support people, she said. Corporate has gone up, but we got on a path to bring the numbers down, Bennett said. The numbers you are seeing on the page 14 chart will come down – there will be IT reductions, and we are using EPIP as a systematic way of evaluating where we can make cuts, she said.

Will you have more refined numbers before the PFR closeout? Gregg asked. I work on this all the time, but I don't have a specific date for new numbers, Bennett replied. We're working on spending levels for the next rate case, Clark stated. What is the timeframe for getting the EPIP levels into rates? he asked.

Bennett explained that after an internal effort to reduce staff did not produce the desired results, BPA hired a contractor, KEMA, to do a rigorous review. KEMA gave us a list of areas where we could look for efficiencies, she said. We are now going through a systematic review to see how to deliver services at a lower cost, Bennett said. She referred to pages 18-19 in the handout, which describe the EPIP process and potential savings, and she pointed out that some of the savings might have more impact on PBL than TBL and vice versa.

This is what we have challenged our teams to deliver, Bennett said. We came up with the numbers by working with KEMA and our own people to do a current-state analysis, she explained. That was "a wake up" for the teams – "it forced them to look at transformational ways of doing their functions," Bennett said, describing each of the functions, baseline costs, and cost reduction challenges on page 19.

Will these savings go into rates? Clark asked. We will attempt to get as much as possible into the initial proposal, Norman replied. The first thing IT did with its budget after consolidation was to add $8 million as soon as the SN CRAC expires, Clark commented. That's not the way to start out a reduction process, he said.

BPA is doing good work in this area, but the reduced numbers don't yet show up in your costs, Dick Helgeson (EWEB) said. We're shooting at all your old numbers – "it's hard to contain our angst about what this means for rate levels," he said.

One of my concerns is that your projected FTE level is flat for 2007-2009, not going down, Lovely commented. We are thinking that is what will go into rates, he stated. What is the target for 2007-2009? Lovely asked. If we see the drive toward reductions, it gives us more comfort, Lovely said. We'd like to see you reflect your lower targets in the next rate period, he indicated.

You want us to incorporate reductions, but we are trying to figure out if we can deliver the savings, Bennett stated. It is important to move forward systematically, Jean Ryckman (Franklin PUD) said. It is harder to do, but it's better than rushing in and making changes without careful thought, she said. Yes, the changes have to be enduring, Bennett agreed.

I get nervous when KEMA tells you "to lop 15 percent off energy efficiency," Cavanagh said. The cuts that are made in energy efficiency are always in the evaluation of results, he said. That is one "that doesn't look broken to me," Cavanagh stated. Some areas may not be broken, but we wanted to challenge everyone to make reductions, Bennett replied. We have to be able to deliver products and services, but we need to ask if there is some efficiency to be gained in energy efficiency management, she said.

Human resources is on the EPIP docket too, Bennett continued. We want to move to an automated system – we are "high touch" at BPA, and we are changing how we do business, she added.

Your FTE chart looks flat out into the future, Howard Schwartz (WA) commented. You don't anticipate staying there, but are reluctant to reflect the cuts, he said. These numbers are from last fall, Bennett responded. Will the rate case reflect the reductions? Schwartz asked. We expect so, she said.

What would it take to curb the increase in the expenses we see in internal operations charged to power? Eldrige asked. The costs are driven by people, and for costs to go down, our staffing would have to go down, Steele replied. The increase seems high, Eldrige said. I've looked at the increase since 1999, and we have added $12 million just in employee costs, like cost of living adjustments, 401(k) match, and health insurance, Steele said. Eldrige suggested corporate pick a substantially lower FTE number it wants to achieve.

Many of Kevin's comments resonate with me, Saven said. Before you close out this process, we need to see the dollars you are cutting out, he said.

Starting in April, the teams will bring in the material they've developed and their proposed savings – for most EPIP reviews, we'll have good ideas by June about where we're headed, Bennett said. We deferred the review of fish and wildlife (F&W) because last year we put in place a new contract management system called PISCES, she explained. All of the contractors must use the system if they get money from us, Bennett said. It's a huge project with a high priority, and we decided we needed to get it in place before we did EPIP – we have deferred F&W, but it will be done, she stated.

Saven pointed out that there is $139 million dedicated to the integrated F&W program and an additional $7 million to $8 million in related BPA overhead costs. About 40 percent of this money is spent on data collection and monitoring and evaluation, so only 60 percent goes to things directly benefiting F&W, he said. So much administrative effort is about "chasing people and numbers" and is not dedicated to projects in the Hs, Saven said. I question whether we have a huge bureaucracy in this organization because of the way the F&W dollars are being spent, he said. I'd like to raise the question of whether we need 60 people working in this area – consider reductions and force changes in the way the dollars are spent, Saven suggested.

It's "a caricature of the customer position," but it sounds like, cut to a certain dollar level regardless of the impact to your program responsibility, Cavanagh said. I hope we see you carry out the fundamental obligations of the agency to meet its mission, he urged. Customers are telling you to manage to the numbers, Cavanagh added.

One thing that can happen with an efficiency process is, there isn't enough follow-up to capture what you have identified you want to do, Elias said. It's 80 percent of an efficiency project, but it's often neglected, he said.

A lot of our costs are staffing, Bennett said. We have limited tools to cut the payroll, she said. We will have a similar number of folks after the review – getting the savings may take longer than I want and longer than you want, Bennett acknowledged. But we can't lose sight of what we need to aim for, she agreed.

We know it is hard to reduce the workforce, Jim Webb (Lower Valley) said. But we need to remember that the reduction is not just in the people, it is also in the dollars those people need to do things, he said. Other budget dollars come down too – by reducing the workforce you force efficiency, Webb stated. We hope to see some of the targets in rates, he added.

Unfortunately, when you encourage people to retire, the wrong people can leave, Eldrige said. What's the possibility of telling people, "I don't have a job for you"? he asked. I don't have a tool to use to tell someone I don't need him or her and offer severance, Bennett replied. The government tool is "reduction in force," and it's a very disruptive process that is done from the seniority perspective, she said. I hope not to have to use it, Bennett stated. We can use attrition based on the demographics in some functions, and we can reassign people, she said. But we don't have many tools, Bennett acknowledged.

The problem with monetary rewards is determining whether they encourage the right behavior, Kris Mikkelsen (Inland) said. I'd suggest aligning any reward targets with the rate target and with benefits for customers, she said. If you get to 27 mills, customers would be receptive to rewards, Mikkelsen added.

We budget $200 per person in our "Success Share," which is a big part of our rewards program now, Bennett replied. That doesn't mean every employee gets $200, she added. We work toward agency-wide targets, so what we do here is close to what you're suggesting, Bennett explained.

Ralph Williams (United Electric) said he applauded BPA for bringing TBL and PBL functions back together where it makes sense. That is one place you can gain efficiency, he said. I support having the account executives in local areas, but I encourage you to combine functions where you can, Williams stated.

I'm looking at the numbers on page 15, and they show costs going up in the next rate period, Clark stated. TBL and PBL costs are going down, but I don't see that with Corporate, he said. Are we going to hold the line in Corporate like the rest of the agency is doing? Clark asked. Costs are coming down across the board at the agency, Bennett responded. You can't just isolate the three functions – they are related, she said.

Bennett explained the corporate costs on page 15. With regard to general counsel, I'd like to see more staff there – "we are burning people out," she said. Bennett noted that the year-to-year fluctuation in costs for general counsel reflect when BPA hired outside legal assistance. She answered questions related to other line items, including the addition of a technology innovation/confirmation program in 2006-2009. The program addresses emerging technologies and investments that offer an opportunity to improve service delivery, Bennett said.

The industry has been underinvesting in technology, Cavanagh stated. There is not much research and development (R&D) going on, he said. The BPA proposal is one-quarter of a percent of the budget – in the high tech industry, R&D is 8 to 10 percent of the budget, according to Cavanagh.

Lovely asked about the growth in line item 20, capital for the COO function. What you see are numbers that were collected from many sources – we know this is not the right trajectory, and these will go down, Bennett responded. The numbers are confusing, Gregg said. We need a number that forecasts the three-year PBL average charge and is updated before the rate proposal comes out, he said.

When we put out our proposal in May, we will explain and crosswalk the new numbers with the originals, Norman said. You will then have three weeks to comment, he said. I don't see a lot of incremental updates between now and then, Norman added.

This is frustrating – we adjust our schedules to be here, and the information you offer in the packet is not accurate, Lovely stated. This isn't the kind of information we need to make decisions – "you've put together numbers that don't mean anything," he said. Let's talk about achievable numbers and goals, Lovely urged.

Norman said the timing for review and reductions in Corporate are not in sync with the PFR schedule. I'll take responsibility – I thought this would be a good compromise, he said. The other alternative was not to talk about it, Norman said. You've given us suggestions, and we'll respond in our PFR closeout and the rate proposal, he said.

In May, it would be helpful for you to give us your intentions about what you'll do in this area, Eldrige said.

III. CGS Update

Andy Rapacz (BPA) offered an updated table on Columbia Generating Station (CGS) O&M. These are numbers people asked us for yesterday, he said. CGS costs are increasing some, Rapacz pointed out, noting the requirements for increased security, rising nuclear fuel costs, and the need to recover from deep cuts in the 1990s.

Isn't the uranium tails project speculative? Cavanagh asked. I would give it an 80 percent chance of success, Rapacz responded.

Which of these numbers would you put in the rate case? Eldrige asked. We should take the O&M savings, tailings project, and assume capitalized costs, he said. The Energy Northwest (EN) board will listen to us and to you about capitalizing costs, Norman said. My leaning is we should borrow to cover the capital costs that are appropriate, he said.

IV. Debt Service

Valerie Lefler (BPA) noted the financial disclosure statement and the agenda for the session on debt. Debt service is made up of depreciation and amortization, federal net interest, and non-federal debt service, she explained. These are "substantial chunks of our cost," and they are the function of other capital investment decisions that are made, Lefler said. We manage debt as a portfolio, and how we manage has an affect on the total, she stated.

A significant portion of what you are seeing is debt that is already there – investments that have already been made, Lefler continued. We'll point out those that are related to decisions yet to be made, she said.

Ron Homenick (BPA) went over depreciation and amortization costs. These are "the most mechanical costs we have," he said. In reality, this isn't something you manage in and of itself; the most important decision is whether the investments are worthwhile in the first place – the primary components of depreciation and amortization are investments that are already made, Homenick said. The largest component is Corps and Reclamation projects, and 30 percent is Legacy Conservation and ConAug, he said.

Homenick listed several drivers of change and noted that "a healthy chunk" of investment is related to the Corps' Columbia River Fish Mitigation (CRFM) project. The bulk of that investment has not been transferred to BPA's books, but most will be brought into service from 2005 to 2014, Homenick said. The table on page 8 shows what will be added to the base, he said, noting that the total is declining as the depreciated life of investments ends. Uncertainty about the CRFM plant-in-service schedule poses the risk of increased costs during the next rate period, Homenick indicated.

Lefler noted that BPA's F&W staff has had separate PFR meetings, which included presentations by the Corps and a 2005 CRFM project list. The list is posted on our website if you want to look at it, she said. We have had meetings with the Corps about the schedule for the CRFM costs going into rates, but we don't know if we will have any influence, Lefler said. They are listening, she added.

Can we influence the amortization schedule for ConAug? Gregg asked. The decision to amortize the investments over the period of the power contracts was based on accounting principles, Lefler said, and we're considering whether it is time to revisit it.

Since we did not specifically address treating the ConAug capital in the rate case, it was decided after the fact, Homenick explained. Since it was tied to resource augmentation, we determined it should be amortized over the life of the power contract, he said. It was during the contract period that we could be guaranteed to recover the cost, Lefler added.

It's time to revisit "this mistake," Clark stated. We saw this treatment for the first time in May 2000, and we pointed it out again in the SN CRAC rate case, he said. Legacy Conservation was amortized over the useful life of the measures that were funded, so this decision was an anomaly, Clark said. It has a $5 million per year effect on 2007-2009 rates, he said.

There was also concern when this decision was made about the costs we are pushing out in front of us, Norman said. The decision went up to "the Steve Wright level," and he said we don't want to punt this cost out into the future, he stated. You can comment on it, Norman added.

I see this as generation, Ryckman said. Would you amortize generation over the life of a power contract? she asked.

The argument was that we were augmenting specifically for the period of the contract, Homenick explained. This treatment guarantees recovery of the investment, he said.

This is something you acquired and it has a useful life, Lyn Williams (PGE) stated. Cutting off amortization arbitrarily doesn't make sense, she said.

Is anyone opposed to changing this? Norman asked. Seeing no one, we have a clear message on this, and we'll factor it into our decisions for the May proposal, he said. The message is, amortization should be based on the life of a measure, Norman restated.

I'm confused about the mystery of when things like CRFM are plant-in-service as opposed to construction-work-in-progress, Mikkelsen said. The Corps will make the decision, Lefler responded. As I understand it, much of the CRFM was mitigation analysis, and the decision was not to bring it into plant-in-service until all of the studies were complete, she said.

Is there risk that some of this investment has no value? Mikkelsen asked. Some may be attached to studies of things that didn't work out, Lefler acknowledged. Look at the Corps packet on the website, she urged. It talks about the regional structure for making decisions on CRFM expenditures, Lefler said.

Homenick moved on to the components of federal net interest expense, and he described BPA's federal capital funding mechanisms: bonds issued to Treasury and capital appropriations. Homenick noted that the table on page 12 excludes any assumption about interest credits, but he said a number will be included in the rate proposal. If you extrapolate from 2002-2004 actuals, you'd see an additional $10 million credit, Lefler pointed out.

Homenick went on to list the risks for increased federal interest expense, which include rising interest rates and a change in the CRFM projected plant-in-service schedule. The opportunities for reductions include aggressive debt management and continuation of the debt optimization program (DOP), he said. Drivers of change in the next rate period include DOP, which increases the repayment of federal debt and reduces interest expense, as well as increased capital investment for a number of programs, including ConAug, IT, F&W, and direct funding for Corps and Reclamation capital projects, Homenick reported.

Don Carbonari (BPA) made the non-federal debt service presentation, noting that BPA takes a team approach to managing debt. The non-federal debt is primarily EN with some smaller projects, he said. People assume that our non-federal debt service obligation has been level from year to year, but it never has, Carbonari said. We shape it in a way that is beneficial, he added. Carbonari went over a list of debt management actions, including DOP. The fundamental reason for DOP was to restore BPA's Treasury borrowing authority, he said. We only restore authority when we pay down federal debt, Carbonari said, explaining that BPA has prepaid about $1 billion in federal debt. We picked certain appropriated debt to pay off and have called almost every federal bond we could, he said.

According to Carbonari, DOP does not impact 2007-2009 rates. We are paying down federal instead of non-federal debt, and that does not affect rates, he explained. Is the benefit applied equally to all groups of customers? Eldrige asked. The timing of benefits is different between Slicers and non-Slicers, Lefler responded.

Are rates lower overall as a result of DOP? Eldrige asked. In 2012, CGS would have been paid off, he said. What would have happened to rates if you had just paid off EN bonds and you had not borrowed more from the Treasury? Eldrige asked. I assume we would have had some capital program, and we'd have been looking at how to fund things with third-party debt, Carbonari answered.

DOP has benefited BPA, but I'm less certain as a ratepayer that I have benefited, Eldrige stated. I have questions about the way this has been done, he said.

If you look at the BPA business model, interest and amortization expense gets higher and higher, Jim Lobdell (PGE) pointed out. We're building debt service and rates aren't enough to cover it, he said. The amount of debt just keeps building – we need to change the slope of the curve so rates cover more of the expense, Lobdell advised.

All we have the right to do now is pay, Eldrige said. We don't have a voice in the capital projects – I'm not so sure it's a big benefit, he stated.

Is the question about the level of capital spending or is it about how it is financed? Schwartz asked. If it's whether accruing more capital debt should be done, I share the concern, he stated.

We do have input into the capital spending decisions, Clark stated. I think this is working, he said. Clark said he is concerned about "paying twice" for the EN principal. For rate setting, you should move the EN debt (principal payment) below the line on your income statement – it's a way to assure that we don't pay twice, he said. It's important for the credibility of DOP, Clark added. The EN debt has been extended, so we should not pay for it again, he said.

Congress could be a lot of help to us, and if we just keep taking care of obligations by refinancing and incurring debt, we don't take the opportunity to educate people about what we really need to comply with the mission that has been given us, Eldrige said. We may be harming ourselves in terms of getting help from outside the region, he suggested. "There are a lot of things I don't agree with that have been loaded onto the system," Eldrige added.

We’re looking at $1 billion in total debt service, Cavanagh said. But how much is the debt from WNP-1 and 3? he asked. The total EN debt is $500 million, in addition to $280 million annually for O&M, Cavanagh said.

There was discussion about the amount of exposure BPA is facing from interest rates, and Carbonari said the forecast for 2007-2009 builds in an interest rate increase. I’d like to see one place where you have the impact of capital programs on rates, Gregg requested.

We’ve gotten a lot of comment on the capital program, Norman stated. As a result, Ruth Bennett will start a new process to explore the aggregate capital program, he said. We will keep you posted, Norman indicated.

Carbonari explained that reserve fund free-ups will have an impact on 2007-2009 rates. We freed up a lot of reserves, and we got the benefit of doing that, but the impact is we will have less revenue from interest, he said. We will have to recover an additional $49 million because of the free-ups, Carbonari said.

He described refinancings undertaken from 2001 to 2004 to secure interest savings, noting that over $3 billion in transactions were completed in that period. Those actions will have a positive impact on 2007-2009 rates, Carbonari reported.

Managing debt as a single portfolio has had significant results, he said. By taking the actions we did, we saved PBL about $112 million annually, Carbonari said. There are other options related to non-federal debt service that could benefit ratepayers in the near term, but they could impact future rates, he wrapped up.

Clark asked BPA to look at various scenarios for retiring third-party debt, including looking at the value in the next five years of continuing to capitalize EN expenses. Don’t look to place any debt beyond the current license of the plant, Eldrige said.

Norman asked for any additions to the debt management items on the scoresheet. Clark said BPA should use the latest interest rate assumptions for the initial rate proposal and address the issue in the rate case. He also suggested BPA look at the effects of stretching out the third-party debt for another five years.

How about getting rid of the repayment study requirement in RA 6120.2 and going to normal FERC accounting, Williams suggested. The conventional wisdom is that while the study is arcane, it helps us rate wise and gives us flexibility, Norman responded. I can’t commit to doing that, he added. Norman agreed to add to the scoresheet lengthening the amortization period for F&W investments and moving the principal payment in the EN debt service “below the line” to the cash-flow statement.

Eldrige asked Norman to encourage Ruth Bennett to base her projections for Corporate on what she thinks she can do. We'll do that, Norman said.

For our next meeting, risk and fish costs are on the agenda, Norman said. They are huge issues he stated. Risk in particular is very amenable to public input. We will put out briefing papers April 1, Norman concluded.

The meeting adjourned at 3:15 p.m.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on an ongoing basis. The Web address is www.bpa.gov/power/review.

Internal operations costs charged to power rates:

1. Please provide the number of FTE in each functional area on page 13 for current vs. 2002 levels.

2. What are the CFTE for BPA?

Debt Service:

3. What is the basis for the capitalized bond call premiums that were said to be in the Capital G&A for FYs 2008 and 2009 on page 15?

UMATILLA INDIAN RESERVATION • SHOSHONE-BANNOCK TRIBES • WASHINGTON FISH & WILDLIFE • SALISH KOOTENAI TRIBES • NATIONAL MARINE FISHERIES SERVICE • YAKAMA INDIAN NATION • IDAHO FISH & GAME • WARM SPRINGS RESERVATION • BURNS-PAIUTE • KOOTENAI TRIBE • SPOKANE TRIBE • MONTANA FISH, WILDLIFE & PARKS • COLVILLE RESERVATION • OREGON FISH & WILDLIFE • NEZ PERCE TRIBE • KALISPEL TRIBE • U.S. FISH & WILDLIFE • SHOSHONE-PAIUTE TRIBE • COEUR D' ALENE TRIBE

COLUMBIA BASIN FISH & WILDLIFE AUTHORITY

PFR-015
APR 05 2005

March 16, 2005

Stephen J. Wright, Administrator
Bonneville Power Administration
905 NE 11th Avenue
Portland, Oregon 97208-3621

Melinda Eden, Chair
Northwest Power and Conservation Council
851 SW 6th Avenue, Suite 1100
Portland, Oregon 97204

Dear Mr. Wright and Ms. Eden:

The Members of the Columbia Basin Fish and Wildlife Authority (CBFWA) are writing to support adequate funding for fish and wildlife in the next Bonneville Power Administration (BPA) rate case. This letter provides a status report on our efforts and a request that BPA increase the level of funding for BPA's Integrated Fish and Wildlife Program (BPA's Integrated Program) over that provided the past several years. We are providing this letter now to inform BPA's upcoming workshops on this issue. The NOAA Fisheries and U.S. Fish and Wildlife Service abstain from consideration of this letter.

Some Members have been working with BPA and the Northwest Power and Conservation Council (NPCC) over the past few months to develop cost estimates for BPA's Integrated Program. To inform these discussions, CBFWA formed a working group to estimate costs to meet the goals and biological objectives in the NPCC Fish and Wildlife Program. The intent was to determine how implementing all the measures in the NPCC Program will affect future funding needs and to size the overall level of effort over the next ten years. The working group subsequently shared drafts of its analysis with BPA and NPCC staffs as well as representatives of BPA's utility and industrial customers.

While CBFWA Members are continuing to review the detailed costs, the analysis completed to date provides a strong basis for increasing the funding for BPA's Integrated Program in the next rate case period to at least $240 million per year. This figure assumes that BPA would use its borrowing authority for new production facilities and the acquisition of land and water to protect habitat. It also does not include a comprehensive assessment of costs for mainstem measures beyond those contemplated in the Updated Proposed Action or the NPCC Program. Additional mainstem measures are necessary to

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protect, recover, and restore anadromous fish impacted by the federal hydrosystem. Consistent with recommendations the Members have made in the past, the analysis supports the need for BPA to begin to ramp up efforts by returning to the funding levels originally assumed in the 2002 rate case. BPA set its rates and has been collecting revenues on the assumption that funding for the Integrated Program would be $186 million per year. It is important to increase funding in FY 2006 to at least this level.

Based on our work to date, it is clear that the current spending levels are inadequate to protect, mitigate, and enhance fish and wildlife under the Northwest Power Act. Our analysis shows that at the current spending levels, it would take over 100 years to implement all the measures contemplated in the NPCC Program.

We invite BPA and the NPCC to work with CBFWA as we refine our analysis. CBFWA will be approaching your staff within the next week to explore ways we can best involve you in our effort. Our goal is to complete our analysis by the end of April as part of BPA's Power Function Review.

The NPCC and BPA have invested significant time, effort and money to develop the current Program, including the development of the mainstem amendment and subbasin plans. It is important that the region build on this investment by all the people in the Columbia Basin. The CBFWA Members will be working with you over the next two months to ensure that future fish and wildlife funding needs are adequately addressed in the next rate case.

Sincerely,

for

Tony Nigro, Chair
Columbia Basin Fish & Wildlife Authority

Cc: CBFWA Members
Greg Delwiche, BPA
Doug Marker, NPCC

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PFR-016
APR 05 2005

Affiliated Tribes of Northwest Indians

2005 Winter Conference
Portland, Oregon

RESOLUTION #05 - 07

"REQUESTING THAT THE BONNEVILLE POWER ADMINISTRATION PROVIDE FULL FUNDING FOR FISH AND WILDLIFE PROTECTION, MITIGATION AND ENHANCEMENT IN ITS 2007-09 RATE CASE"

PREAMBLE

We, the members of the Affiliated Tribes of Northwest Indians of the United States, invoking the divine blessing of the Creator upon our efforts and purposes, in order to preserve for ourselves and our descendants rights secured under Indian treaties, executive orders and the federal Trust Responsibility, and benefits to which we are entitled under the laws and Constitution of the United States and several states, to enlighten the public toward a better understanding of the Indian people, to preserve Indian cultural values, and otherwise promote the welfare of the Indian people, do hereby establish and submit the following resolution:

WHEREAS, the Affiliated Tribes of Northwest Indians (ATNI) are representatives of and advocates for national, regional, and specific tribal concerns; and

WHEREAS, the Affiliated Tribes of Northwest Indians is a regional organization comprised of American Indians in the states of Washington, Idaho, Oregon, Montana, Nevada, Northern California, and Alaska; and

WHEREAS, the health, safety, welfare, education, economic and employment opportunity, and preservation of cultural and natural resources are primary goals and objectives of Affiliated Tribes of Northwest Indians; and

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Phone: 503/249-5770 • Fax: 503/249-5773

WHEREAS, the Bonneville Power Administration (BPA) has a Trust Responsibility to the Columbia Basin tribes; BPA funds measures to protect, mitigate and enhance fish and wildlife under the Northwest Power Act and recovery efforts under the Endangered Species Act (ESA); BPA is developing fish and wildlife costs for Fiscal Years 2007, 2008 and 2009 for inclusion in its next rate case, in which BPA will establish the rates it will charge for the electricity that it markets from the federal dams; and

WHEREAS, the Northwest Power and Conservation Council (NWPCC) has determined that the federal hydropower system was responsible for the loss of five to eleven million salmon and steelhead in the Columbia River, the loss of resident fish and resident fish habitat, and the loss of wildlife and wildlife habitat that were damaged by the construction, inundation and operation of the Federal Columbia River Power System (FCRPS); and

WHEREAS, the NWPCC has set a goal to double existing salmon and steelhead populations in the Columbia River (from 2.5 to 5 million annual returns) and set goals to mitigate for wildlife and resident fish losses caused by the construction, inundation and operation of the FCRPS; and

WHEREAS, the NWPCC has adopted specific policies and recommendations for resident fish substitution for areas where salmon and steelhead runs are completely blocked by federal dams; and

WHEREAS, Columbia Basin fish and wildlife managers worked with watershed councils, community groups, the NWPCC and BPA to develop subbasin plans for the entire Columbia Basin to address the goals, biological objectives, and other requirements of the NWPCC's 2000 Fish and Wildlife Program, and have developed cost estimates for implementing these subbasin plans; and

WHEREAS, the heads of NOAA Fisheries, BPA, the U.S. Army Corps of Engineers and the Bureau of Reclamation have asserted their "firm commitment to ensure the survival of Columbia Basin salmon" and other fish and wildlife, and written approvingly of these subbasin plans, stating that ". . . a remarkable collaboration of local citizens, landowners, tribes and state and federal agencies has produced draft fish and wildlife plans for 59 Colombia River sub-basins"; and

WHEREAS, an aggressive schedule to implement subbasin plans will result in efficient and cost-effective protection, mitigation and enhancement of fish and wildlife, while delayed implementation will result in greater actual costs and opportunity costs; and

WHEREAS, federal actions to address the protection, mitigation and enhancement of fish and wildlife impacted by the FCRPS have thus far been inadequate; and

WHEREAS, aggressively implementing subbasin plans will address federal laws and the federal Trust Responsibility and Environmental Justice and equity issues, and will result in significant progress toward achieving the goals of the Northwest Power Act, the ESA, and the United States' treaty obligations and Trust Responsibility to Columbia Basin Indian tribes; and

WHEREAS, implementing the subbasin plans will support rural and tribal economies, construction and recreation jobs, and tribal and non-tribal fisheries, and will improve environmental quality; and

WHEREAS, implementation of subbasin plans is consistent with, and will further, the goals of the NWPCC's 2000 Fish and Wildlife Program;

NOW THEREFORE BE IT RESOLVED, that the Affiliated Tribes of Northwest Indians requests that BPA, the NWPCC, and other regional decision-makers support adequate funding for fish and wildlife in the BPA rate case; and

BE IT FURTHER RESOLVED, that these funding commitments must be directed to address the impacts to fish and wildlife in the Columbia Basin above Bonneville Dam as a first priority, that such funding must be directed to measures that complement the tribes' existing and future fish and wildlife management, that such funding not be used to support mass marking activities, and that such funding will only support those projects that are wholly consistent with the federal government's treaty, trust, and other obligations to the Basin's tribes; and

BE IT FINALLY RESOLVED, that the Affiliated Tribes of Northwest Indians supports the budget developed by the fish and wildlife managers for the implementation of the subbasin plans and other measures to address the Integrated Program, including the proposal submitted to BPA by the Upper Columbia United Tribes; the Integrated Program budget (for implementation of the Fish and Wildlife Program and the FCRPS Biological Opinion) identifies funding needs of $189 million in FY 2006, $250 million in FY 2007, $300 million in FY 2008, and $350 million in FY 2009.

CERTIFICATION

The foregoing resolution was adopted at the 2005 Winter Conference of the Affiliated Tribes of Northwest Indians, held at the Embassy Suites Hotel Portland Airport in Portland, Oregon, on February 10, 2005, with a quorum present.

Ernest L. Stensgar

Ernest L. Stensgar, President

Norma Jean Louie

Norma Jean Louie, Secretary

PFR-017
APR 05 2005

April 1, 2005

Stephen J. Wright, Administrator
Bonneville Power Administration
905 NE 11th Avenue
Portland, Oregon 97208

Melinda Eden, Chair
Northwest Power and Conservation Council
851 SW 6th Avenue, Suite 1100
Portland, Oregon 97204

RE: BPA Customer position on a Fish and Wildlife Program Memorandum of Understanding (MOU)

Dear Administrator Wright and Chair Eden:

For almost a year, the Northwest Power and Conservation Council (Council) and Bonneville Power Administration (BPA) have engaged in a process to reach agreement on a Memorandum of Understanding for BPA's Direct Program for fish and wildlife. The purpose of this letter is to clarify further the customers' position on an MOU and to request that a long-term funding agreement not be entered into at this time.

The MOU as currently discussed neither provides additional certainty within the total costs borne by ratepayers for fish and wildlife, nor does it create a comprehensive prioritization or performance-based funding mechanism that would ensure a cost effective method of achieving the stated goals of BPA's Direct Program.

Utility and industry interests recognize the responsibility to address effects to fish and wildlife caused by operation of the Federal Columbia River Power System (FCRPS). And, because BPA's customers bear the costs of fish and wildlife mitigation programs through wholesale power charges and lost generation, they are seriously committed to seeing that the programs succeed. Customers reasonably wish to see the resources made available for mitigation used in the most cost effective and efficient manner possible. (See enclosed "Customer Principles for a Long-Term Funding Agreement for Fish and Wildlife".)

In the last several years, BPA's fish and wildlife expenditures have risen significantly. Since 1996 (the first year of the prior Memorandum of Agreement) expenses associated with BPA's Direct Program have increased from $68.5 million to about $146 million (including capital), representing a doubling in size of the program in eight years. This is an order of magnitude of growth that far outpaces the rate of inflation, and mandates a wholesale review regarding policy development and financial parameters guiding the program.

At the same time, as part of its Power Function Review (PFR), BPA has estimated that its total Fish and Wildlife Program's annual average cost will be $691 million by 2007. This figure includes the Direct Program, hydro operations costs, capital and operations and maintenance costs for Corps of Engineers' and Bureau of Reclamation facilities, funding for US Fish and Wildlife Service, and other components. All of these factors compose the fish and wildlife component of BPA's total revenue requirement, and must be made up through rates collected from electricity consumers.

In total, fish and wildlife costs make up over 20 percent of BPA's revenue requirement. Until these expenditures are recognized as a single, integrated program in which costs and effects are inseparable, identifying the most biologically and cost effective measures for fish will not be possible.

The BPA Joint Customers have established a Priority Firm rate target for the period beginning in FY 2007 of $27 MWh, including accommodating risk. We are vigorously pursuing that goal through the PFR and in other forums. In practical terms, it will be impossible to derive an acceptable rate figure without achieving greater efficiencies in the fish and wildlife program.

Uncertainties in the Region

As BPA heads into its rate case for the years 2007 – 2010, there are noteworthy uncertainties in the region that could have severe effects on the costs of BPA's total fish and wildlife program:

- The 2004 Biological Opinion is currently being litigated. An adverse judgment in this case could increase mandatory fish spending by as much as $200 million or more annually. Increased costs that result from the litigation will likely be borne disproportionately by the ratepayers.

- The Columbia River Basin has endured several consecutive years of low water runoff. Thanks to good ocean conditions and the past investments of the region's ratepayers, salmon and steelhead have thrived, with record or near record returns each year since 2000. These low water conditions have a different effect on rates for electricity consumers, however. A report presented at the February 16, 2005, Council meeting conservatively estimated that this year's low runoff would make implementation of the BiOp 10 percent (or about $60 million) more costly than it would be under average water. Though precipitation totals have improved recently, they are still well short of average, signifying that BiOp implementation may be even more expensive.

- NOAA Fisheries intends to produce draft recovery plans for each of the Basin's Endangered Species Act (ESA) listed fish by the end of this year. While the scope of these plans is yet to be defined to the extent that ratepayer funds play a role, that funding must be prioritized within other fish and wildlife spending in the Council's Program. It is simply not acceptable to create further funding expectations of BPA's ratepayers without a comparison with the biological cost-effectiveness of current investments. Locking into a program without this information as a guide is premature.

Fish and wildlife costs already make up over 20 percent of BPA's total revenue requirement. The estimated $700 million required is more than the annual cost associated with BPA's transmission system. Outside of BPA's treasury repayment obligation, it is the single largest component of BPA's rates. Amidst these escalating demands on ratepayer dollars, BPA and the Council should work together to control BPA's costs in order to maintain an economical and reliable power supply for the region. It is unwise for BPA and the Council to add another layer of non-discretionary funding in the form of a long-term funding agreement to BPA's fish and wildlife obligation.

The Scope of an Understanding

Throughout the MOU discussions, customers have requested a clear statement of the biological goals and estimates of the biological benefits that BPA's investments are achieving. Though we recognize the difficulty in these calculations, we are frustrated that estimates of the biological benefits are generally not available and that the Council and BPA have not made it a fundamental requirement that fish and wildlife expenditures be justified. Without knowing the biological goals, it is impossible to evaluate the cost-effectiveness of alternate approaches for achieving those goals.

Customers believe that the basis of an understanding between BPA and the Council should be a foundation for establishing the Basin's funding priorities and determining BPA's obligation. An MOU that features a funding commitment as its chief component has it the wrong way 'round. This approach seems to focus solely on obtaining a specified dollar amount year after year, not on what can best be done for fish with limited resources. A successful understanding should be measured primarily by the achievement of favorable performance-based results for fish and wildlife populations, not on dollars collected and spent.

Outside of the funding discussion, customers can be supportive of an agreement that is limited to improving efficiencies in project selection or bolstering the cooperative working relationship between the Council and BPA. As stated in the Customer Principles, customers believe that increasing the role of cost-sharing and increasing incentives for cost-effectiveness in the project selection process are important goals. It is clear that not all of the Basin's limiting factors for salmon survival are due to the construction and operation of the federal hydrosystem. Many of these factors have no, or only a partial, relationship to the existence of the dams. Fairly apportioning the costs across the responsible parties makes sense for the region.

The customers are very supportive of BPA's initiative to increase the *on the ground* allocation of the Direct Program. The proportion of money identified for programs such as coordination, research and evaluation, monitoring and data collection, is disproportionately high compared to more fundamental activities directly benefiting fish, such as habitat and production.

Current activities that result in spending $139 million expense and $36 million capital per year need to be thoroughly prioritized based on biological benefits. Until an evaluation of this type is completed and it can be clearly shown what level of funds is needed to achieve the Program's biological goals, we see no justification to increase current expenditure levels. Consistent with the Customer Principles, any additional funding for the Direct Program should not result in an increase in total fish and wildlife spending for BPA's ratepayers.

Conclusion

Customers seek a low, cost-based power supply from BPA that allows us to maintain the region's economic viability while fulfilling the agency's legal responsibilities of environmental mitigation. This can be achieved only by giving very serious examination to fish and wildlife costs, which are a large and rapidly growing component of BPA's cost structure. Entering into a long-term funding agreement will not allow BPA the flexibility it needs to prioritize its total fish and wildlife expenditures. We appreciate being involved with the process and thank the Council and BPA for the opportunity. We stand ready, and will devote the necessary resources, to work with both entities to identify the programs and projects that are best for fish and good for the region.

Sincerely,

Pat Reiten
President and CEO
PNGC Power

John D Saven

John Saven
Chief Executive Officer
Northwest Requirements Utilities

Jerry Leone

C. Clark Leone
Manager
Public Power Council

Enclosure

cc: Northwest Power and Conservation Council
Greg Delwiche
Doug Marker

Customer Principles for a Long-Term Funding Agreement for Fish and Wildlife

Utility and industry interests recognize the responsibility to address effects to fish and wildlife caused by operation of the Federal Columbia River Power System (FCRPS). Because Bonneville Power Administration (BPA) customers bear the costs of fish and wildlife mitigation programs through wholesale power charges and lost generation output, they are among the most committed to seeing the programs succeed. However, customers also reasonably expect that the resources made available for mitigation will be used in the most cost effective and efficient manner possible, consistent with a comprehensive recovery plan. The following principles are reflective of this expectation.

Performance Based/Results Oriented

Any viable funding agreement between the Northwest Power and Conservation Council (Council) and BPA must prioritize projects within the Fish and Wildlife Program, consistent with an integrated and scientifically based recovery plan, so that the region's limited resources are used in the most cost effective manner. Each project should have clearly defined goals, objectives and measures of performance that fit within the comprehensive plan. The plan should be administered in a manner that assures accountability for all parties involved, and includes open public participation. Justification for financial resources for additional mitigation measures should be established and understood.

Success should be measured primarily by achievement of favorable performance based results for fish and wildlife populations that are listed under the Endangered Species Act, pursuant to an integrated and scientifically based recovery plan. The continual focus should be on attaining real goals for fish, not on dollars spent.

Tie Between Funding and BPA Financial Health

In order to promote and maintain economic stability in the region, fish and wildlife funding levels and program demands should be tied to BPA's ongoing financial health.

Integration of Power Act and ESA Responsibilities

NOAA-Fisheries is still preparing its recovery plan for ESA listed stocks of salmon and steelhead. Without a *comprehensive and integrated* plan, it is impossible to prioritize where resources can be put to their highest and best use. A comprehensive plan must include:

- An analytical foundation based on the Best Available Science, which should include a review from a wide range of interests within the scientific community
- A clear identification of how the comprehensive plan mitigates specifically and solely for the effects to fish and wildlife caused by the operation of the FCRPS
- A detailed description of alternative approaches to mitigation opportunities, and the rationale and criteria for approaches selected
- Flexibility to incorporate new research
- A method to prioritize mitigation opportunities between fish and wildlife populations across watersheds and jurisdictions
- Guidelines to assure mitigation is implemented in the most cost effective manner
- Coordination among all parties funding and implementing mitigation in the region
- An achievable end point and definitions for success.

Cost Effectiveness

Fish and wildlife managers must share in the responsibility for prioritizing resources committed to fish and wildlife mitigation. Currently, there are few demonstrated formal incentives for managers to consider efficiencies and cost effectiveness when developing mitigation options. An agreement must include an IEAB or similar review for every project before funding is approved.

Inclusion of All Costs

In order to accurately reflect the commitment made to the fish recovery effort, and to allow for greater flexibility and cost effectiveness, an agreement should include all direct and indirect cost categories associated with fish and wildlife mitigation activities. These include, but are not limited to:

- Operational costs (*i.e.,* lost generation)
- Administration of the fish and wildlife program
- Reimbursed costs to the U.S. Army Corps of Engineers for their Columbia River Fish Mitigation Program
- Appropriated Capital

"Zero-Based" Funding

Programs should be built around scientifically based and agreed upon biological goals within a comprehensive plan, and should be subject to year by year accountability for results. An annual review should include a mechanism or procedure to discontinue project funding if it is determined that a particular project is no longer biologically effective or useful compared to alternatives, or is no longer needed to achieve the plan's performance measures.

Each year, only those programs that are determined to be biologically effective or needed, when compared to alternatives, should receive new or continued funding. Critical infrastructure and needed O & M would retain funding year after year.

Cost Sharing

An agreement should encourage cost sharing for all mitigation projects. Other potential funding partners should be identified and pursued to avoid duplication of efforts, maximize effectiveness of programs and to stabilize costs for the region's ratepayers.

Conclusion

The customers concur with BPA Administrator Steve Wright's position, as referenced by the following quote:

"BPA is willing to explore the possibility of a broader, long term MOA on fish & wildlife costs for the post-2006 period, providing it provides a clear definition of BPA's obligations, outcomes to be achieved, cost-effectiveness tests, and contemplates the ability to tie funding to Bonneville's financial health so that funding adjusts in correlation to good and bad times."

Administrator Steve Wright to Council Chair Judi Danielson; October 3, 2003

What is the "UCUT Proposal"?

- The Upper Columbia United Tribes (UCUT) propose a comprehensive approach to implement adopted subbasin plans in the Upper Columbia Ecoregion.
- Approach is comprehensive because it encompasses scientific review, specific biological outcomes, and a regional allocation of BPA funding.

Why did the UCUT develop this proposal?

- Desire to move from plans to implementation – achieve PM&E results on-the-ground.
- Recognition that BPA's budget can/should not cover all watershed needs.
- Desire to move toward equitable regional allocation of BPA funding.

What steps did UCUT take?

1. Timely submittal of subbasin plans (subsequently reviewed by ISRP and adopted by NWPCC).
2. Submittal of measures (as required by NWPA) during comment period (adopted by NWPCC).
3. Submittal of 10-year estimate of costs to implement plans at reasonable pace.

UCUT steps (continued)

4. Submittal of proposal for 10-year funding agreement with formula for regional allocation.

5. Submittal of table of biological outcomes to be achieved with regional share of funding over 10 years.

How did UCUT determine all measures are BPA's responsibility?

- UCUT member Tribes' managers, with many years of involvement in the NWPCC Program, are distinctly familiar with limits of BPA's obligations under NWPA.
- UCUT actively seek/obtain other sources of funding, both to address non-BPA needs and to maximize effectiveness of BPA $$.

Examples of subbasin plan focus of BPA's responsibility vs. others.

- Kalispel Tribe uses BPA money to restore riparian habitat along fish-bearing stream, but obtained combination of USFS and DOT $ to address a Forest Svc. Road causing siltation in that stream.
- Spokane Tribe uses BPA & Tribal money to acquire wildlife habitat, adds NRCS money for watershed restoration on interior streams.
- Kootenai Tribe uses EPA, BEF, NRCS, EPA and other grants to augment planning, restoration and enhancement activities.

How much money is involved in UCUT proposal?

- Implementing all measures at a reasonable pace over 10 years is estimated at average $45.3M expense and capital combined (amounts vary each year).
- This would address anadromous, resident and wildlife, listed and non-listed, Tribes and their management partners, and CPI.

How much $$? (continued)

- If stable funding is provided over 10-years, with flexibility to adjust internally, the average is reduced to $29M expense and $13.5M capital.
- Cost savings are from: reduced process costs, ability to take advantage of opportunities and prioritize internally.

Would this amount be in addition to other F&W costs?

- No.
- UCUT costs are in the Integrated Program budget.
- UCUT amount would remain the same, regardless whether Integrated Program budget remains at $139/36M, or increases.
- If no increase, would redistribute to Upper Columbia Ecoregion.
- U.C.E. still <23% expense, 37.5% capital budgets, covering 8 headwater subbasins.

What is the method for equitable allocation of funding to Upper Columbia Ecoregion?

- UCUT proposes give all 62 subbasins an equal base amount.
- Adjust that base to equitable apportionment.
- Mitigation proportional to fish and wildlife losses and relative to benefits derived from each dam (JCCA allocation or Hydro O&M allocation).

An illustration of the UCUT formula:

Inter Mountain Province

Base Exp. 6/62 of $127M	$12,290,000
Adjust. for 40% impact to wildlife and salmon	$ 3,687,000
JCCA above 70%	$ 2,667,000
Expense sub-total	$18,644,000
Capital	$ 9,000,000
Total	$27,644,000
Max. historic Allocation	*$11,000,000*

How does proposal address regional goals?

- Supports 70/15/15 percentage allocation to anadromous, resident fish and wildlife.
- Supports BPA goal of 70/25/5 percentage allocation to put more $$ on the ground.
- Supports longstanding NWPCC Program goals of mitigation in Blocked Area.

How does proposal move toward achievement of goals/closure on BPA obligation?

- Wildlife habitat units at 3 dams (at 1:1) would be acquired and move into O&M mode.
- Resident fish substitution for lost anadromous fish as itemized in table of biological outcomes
- Okanogan anadromous stocks as itemized.
- Addresses listed anadromous and resident fish and species on borderline of listing.

Other questions?