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

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. <u>Corps and Reclamation O&M</u>

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.

O&M Program

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.