Bonneville Power Administration
Power Function Review Regional Meeting
April 21, 2005

WinGate Inn, Missoula, Montana
Approximate Attendance: 25

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

Introduction

Paul Norman (BPA) opened the meeting by explaining that BPA is looking toward the process of setting its rates for 2007-2009. We are here to talk about the costs that will go into those rates, he said. Costs are key to rate setting, but we don't address them in the rate case – we establish them ahead of time, Norman said. We want to hear from those for whom these costs make a difference, he said. The question for us in the Power Function Review (PFR) is, how low can we get our costs and still do what we have to do – how do we carry things out "without spending a nickel more than is necessary," Norman stated.

We have been at this since January, and this is the fourth of five regional meetings, he went on. On May 2, we will put out a draft letter proposing what to do with costs for the rate case, and we'll take comments until May 20, Norman said. We'll put out a final letter in mid June, telling people the cost levels we will take into the rate case, he said.

The costs we propose could go down from where we started in the PFR, but I don't know by how much, Norman said. Customer input makes a difference, and it's good for us and for other agencies to hear from you, he added.

Norman went over the 10-year rate history and pointed out that rates jumped from 2001 to 2002, when BPA augmented its resources to serve load. Rates came down a little, but not much, he said. BPA's power rate is cost based, but other things matter too, he said. Credits, particularly secondary revenues, are an important ingredient in rates, and so is risk, Norman pointed out. We determine credits, loads, and risk in the rate case, but risk is such "a big deal" for us now that we have started talking about it in the PFR, he said.

The PFR is looking at all of the costs that go into rates, Michelle Manary (BPA) explained. The bar chart in the meeting packet (p. 5) stacks our costs, which add up to $2.5 billion to $2.7 billion, she said. In the PFR, we are going through each category, and we are asking, is this the least we can spend and still fulfill our mission, Manary said.

We took all of our costs and subtracted a ballpark estimate of secondary revenues and came up with an average cost in the next rate period of $28 per megawatt-hour (MWh), she continued. If our assumptions about costs, credits, and loads were perfect this is where we would be, Manary said.

But there is a range of risk to consider, she said. Hydro production and market price are the biggest variables we face – this is what we have to deal with in risk, Manary stated.

If we deal with the risk by setting a fixed rate, our rate would be up around $36 per MWh, she continued, but "we know that's too high." The way we design the rate can make it possible to vary with the revenues, Manary explained.

As much as we disliked the cost recovery adjustment clauses (CRACs), if that's how we have to take on the risk, I'd rather see that than have BPA build up a big reserve, Ken Sugden (Flathead Electric) said. You are less likely to watch your spending if you have a big fund built up, he said. Any of us would, Sugden added. It's also "an attractive nuisance" to non-customers and other stakeholders looking to BPA for funds, he said.

We are asked why rates aren't going down since we won't have the augmentation costs we've had in this rate period, Manary said. It's because we are doing a lot more for our customers and constituents in 2007-2009, she stated. Manary went over a list of reasons costs are going higher, including IOU benefits, F&W program costs, increased public utility load, O&M and debt service increases, and conservation and renewables discount.

Ric Brown (Ravalli County Electric) asked about BPA's flexibility in terms of serving public load if it does not have enough resources. We are referring here to load we have already contracted to serve, and we will have it for the remainder of the contract period, Norman answered. But what about a new public forming, like PGE? Brown asked. We said in our short-term Regional Dialogue decision that a new public would have to have a contract with us by June 2005 to get service at the current preference (PF) rate, Norman replied. We would have to serve a new public, but we could charge it for resources we have to go acquire, he stated. Through 2009, that would be the case, Norman added.

Why are the IOU benefits so variable? Greg Jergeson (Montana PSC) asked. The benefits in the next rate period will be based on a formula that relates to the market price of power, Manary responded. Every year we look at the market and base the benefits on the difference between the market and the PF rate, she explained. The benefits have a floor of $100 million and are capped at $300 million, Manary said. The market has been so high, we think we will be at the high end of the range, Norman commented.

We are also seeing an increase in hydro O&M for the Corps of Engineers and Bureau of Reclamation and in our debt service expense, Manary said. We are looking to see if we can get those costs down, she said. The conservation and renewables discount is another item increasing our costs – it's small, but we didn't have it in 2001-2006, Manary pointed out. We have some offsets to our expenses, including reduced aluminum load and higher market prices, but the offsets are not nearly as much as the increases, she stated.

Have you made a decision on the DSIs? Ralph Goode (Mission Valley) asked. No, we haven't, but we do have a $40 million "placeholder" in the budget, Manary responded.

We are facing more risk than ever before, she continued. We're seeing high natural gas prices and a wide range of market-price fluctuation, Manary explained. But wouldn't your secondary revenue be higher with high market prices? Mark Stauffer (NWE) asked. Yes, that's true, Manary said. Whatever we choose for the secondary revenue credit can offset costs, and we can choose a high or a conservative number, she said.

I note that you have risk associated with wind, and you said it's about $10 million annually, said Bill Drummond (Western MT G&T). How much average energy does that risk relate to? he asked. It's about 60-70 aMW, Larry Kitchen (BPA) said. "If the wind doesn't blow, we don't pay for the resource," Norman said. But you may have to replace the resource, if it doesn't happen, Drummond pointed out. There is a huge discussion going on about the wind resource in Montana, and I'm trying to understand the risk associated with it, he explained. Our $10 million estimate is a ballpark – we need to get a more firm number for that, Norman said.

Our packet contains a list of things we have heard so far, Manary said. We've listed the suggested changes according to program areas, and if we took them all, it adds up to about $90 million to $100 million in reductions, she said. This is everything people have suggested so far, and we will be considering all of the suggestions we receive and putting out a draft closeout letter May 2, Manary wrapped up.

I'd second the suggestion that you remove the geothermal project from rates, Drummond said. The developer is in breach of contract, there are transmission problems associated with the project, and "it's horribly expensive," he said. Get rid of it, Drummond advised.

Norman explained that BPA is in binding arbitration over the project. We don't think we owe the developer anything further, but the arbitrator will decide, he said.

The Columbia Generating Station is an example of how a process like this works, Norman said. We worked with the Sounding Board, which was a broad group of customers and public interests, to look at costs, he said. The board prepared a report that said Energy Northwest (EN) needed to tighten up on cost management, Norman said. Since then, EN has taken a very aggressive look at costs and come up with a $23 million annual O&M reduction, he reported. That was due in part to this public process, according to Norman. EN had to come before the customers and make a pitch on its budget – it's is the single largest reduction we've seen, and "we'll count it," he said.

I'd like to compliment your staff on taking a very open approach to addressing risk, Drummond said. He asked for an explanation of what is happening with the Treasury payment probability (TPP). Is it increasing or is the figure a product of a three-year versus a five-year rate period? he asked. The standard came from the 95 percent TPP for a two-year period that we set 10 years ago, Norman said. We relaxed the standard in the last rate case, and now we are talking about returning to that historic standard, he said.

Is it the increase in the TPP, up from where we are now, that is making the rate higher? Brown asked. Yes, Norman responded. If we didn't have to worry about risk, we'd have a sizable rate decrease, but the TPP is holding the rate higher, he explained.

Sugden asked why BPA decided to return to the old TPP standard. In the 1990s, we went through a process to set the standard, and we told the bond rating agencies and OMB where we would set it, Norman responded. We backed off this standard in the current rate period to avoid even greater rate increases. But if we don't return to the established TPP standard it will send a signal about BPA's commitment that will hurt our bond rating. It also seems like the wrong time to look like we are relaxing the standard in light of the Administration's view of cost-based rates, Norman pointed out. There are a wide variety of ways to meet the standard that have lower rate impacts and this is what we should focus on, he said.

We went into this process with a $2.7 billion cost estimate, and "we will be whittling that down in a non-trivial way," Norman stated.

Goode asked about One BPA, the exploration of consolidating some PBL and TBL functions. Do you think you will have a solid number by June? he asked. We're now undergoing an internal review to finds ways to bring costs down, Norman said. We might not know much by June, but when rates are set next year, we will have a better handle on what this will bring us in terms of internal cost reductions, he said.

Looking at the range of rate options to incorporate risk, you go from a flat rate with a large risk premium to CRACs, Stauffer said. Slice customers essentially self-insure their risk, he said. How about letting other customers self-insure? Stauffer asked. If you can't pay Treasury, the customer could write a check for its share, he suggested.

We are open to those types of ideas, Norman replied. Adding eight or nine mills for risk onto the rate is "a non-starter," and we have to look at alternatives, he said. But there is a limit to what customers want to risk, Norman added.

The risk premium is a big hurdle for getting to 20-year contracts, Stauffer stated. When customers see that hurdle, it doesn't help with getting to the longer contracts, he said.

Your risk is biggest in the first year, Drummond pointed out. To the degree you can address the problem in that year, it would be best, he said. Yes, we agree – why build costs into the later years if we don't need to, Norman replied.

Doug Grob (Flathead Electric) asked if the risk management options build BPA reserves. We are estimating that we will end 2006 with $180 million in reserves, Manary responded. Our TPP model is really concerned about getting us over the hurdle in 2007, so it tells us what we need in terms of revenue to get to the standard, she explained. According to the model, if we had $1.2 billion in reserves, we would not need to plan any revenue for risk, Manary said. "We are in a different world now in terms of how wide the swings in secondary revenue can be," Norman added.

The meeting adjourned at 6 p.m.