Bonneville Power Administration
Renewables Focus Group
June 7, 2005

Attendance List

Lori Blasdel, BPA
Orville Blumhardt, BPA
Geoff Carr, NRU (by phone)
Annick Chalier, PPC
Syd Conger, BPA
Carel DeWinkel, ODOE (by phone)
Allan Ingram, BPA
Debra Malin, BPA
Tom Osborn, BPA (by phone)
Rick Rozanski, McMinnville (by phone)
Thad Roth, Columbia River PUD
Dawn Senger, City of Richland (by phone)
Martin Sheeran, City of Richland (by phone)
Lyn Williams, PGE

Deb Malin (BPA) opened the meeting and explained the handouts: two spreadsheets and a draft policy manual on the criteria for renewable resources eligible for a credit in the next rate period. She indicated she would like comments on the draft manual by June 21. After I get comments, I'll prepare a final version that will go to BPA management for approval and then out for public comment, Malin said. I'd particularly like your thoughts on Table 2, which is near the end of the manual, she stated.

Wind Analyses

Orville Blumhardt (BPA) went over the first spreadsheet containing generation data from BPA's renewable projects. This is a look back that summarizes the historical wind deliveries to BPA, he said. It compares, by fiscal year, our average purchase price with the Dow-Jones (DJ) Mid-C value, Blumhardt explained. The BPA average from 2002 to 2005 was $42.27 per megawatt-hour (MWh), he said. This includes some integration cost for Foote Creek and transmission charges paid to PacifiCorp, Blumhardt pointed out. We paid about $11 more than the average Mid-C price, which was $31.12, he said, adding, "that did not surprise anyone."

Geoff Carr (NRU) asked for more detail on the analysis, and Blumhardt explained how he had compiled the data from the wind projects and made a comparison that took into account high and low load hours.

The next spreadsheet is a forward look, Blumhardt said. He went over BPA's forecast wind purchase costs (June 2005 through December 2007), comparing those with the average DJ Mid-C forecast. The figures reflect the BPA trading floor's forward price curve, Blumhardt clarified. In the previous meeting, we discussed that wind purchases going forward would have more value, and this analysis bears that out, he said. For a 31-month period, the BPA average purchase price is $41.20 compared with the DJ Mid-C of $53.55, Blumhardt said. He noted that BPA is about to change the price forecast that was the basis for the analysis, so the outcome would look slightly different.

We keep getting questions about Elliott Mainzer's comment that BPA would be making money on wind, and this is what he was thinking of, Malin commented.

Syd Conger (BPA) explained that there has been confusion about the $10 million risk figure forecast for the rate case that is associated with wind projects. The risk team set a standard such that if we face a risk of at least $10 million, we would include it in the rate case figure, he said. That's why the $10 million surfaced with regard to wind, Conger clarified.

We are not talking about a $10 million expected loss; we are talking about a probability analysis, he continued. The probability of the loss associated with wind is 5 to 10 percent based on the market price outlook at the time I did the analysis, Conger said.

He explained how the analysis was conducted, noting that he used data from Condon, Klondike, Stateline, and the Foote Creek projects. We didn't have a lot of data, Conger acknowledged.

From the data, you can model the daily, monthly, or annual risk, Conger said. We constructed the output probability from the data we had, he said, explaining other details of the 3,000 simulations run for the analysis.

The risk associated with the wind projects is twofold, Conger said: first, the wind output varies, but the key risk relates to what we pay for wind generation versus what we can sell it for. That is the $10 million risk, he said. I used the annual (as opposed to daily or monthly) variability of wind generation for the analysis, Conger explained, and added that when the figure is finalized for the rate case, it will include the comparison with high and low load hours.

Since you purchase at a set contract price, the risk seems to be related just to the market price, Annick Chalier (PPC) commented.

Conger went on to point out that the $10 million risk could be either a shortfall or a windfall. The standard deviation is $6 million to $7 million, and the results are pretty symmetrical, meaning the risk goes equally in both directions, he explained.

Overall, the average annual wind output is about 2 aMW, Conger said. The daily generation "is all over the place," but the variability shrinks a lot with the monthly and annual averaging, he stated.

Wind generation is competitive, and the risk is symmetrical; we could make or lose $10 million annually, Conger summed up.

Is there a correlation between wind generation and weather in the region? Lyn Williams (PGE) asked. If there is, it is hard to establish quantitatively because there is so little data, Conger responded. Trying to establish that "would be a real nightmare," he added. You could see certain types of patterns, but we don't have enough history, Blumhardt agreed. This year, when we had so little rain in the winter months, our wind generation was way down, Malin pointed out. We had a 17 percent capacity factor, she said.

We can see seasonality differences among the plants, but there's not enough data to tell yet, Allan Ingram (BPA) added.

Draft Criteria

Malin moved on to the draft policy manual on the criteria for renewable resources. She pointed out changes and asked for comments and questions as she went through the document.

Beginning with the first three paragraphs of the policy, Main said there would never be more than $6 million transferred to renewables from the conservation and renewables discount (C&RD). If we exceed that amount, it's likely that a pro rata reduction will be made to utility claims because we need to stay under the $6 million cap she said. We haven't made a decision yet on whether that will come from bilateral contracts, though we think it will, Malin said, explaining that the proposal is to reduce contracts on a prorated basis if the total exceeds $6 million. She said BPA is contemplating exempting small utilities (less than 7.5 aMW) and federal agencies from the prorated reduction. We are contemplating letting utilities make claims before each fiscal year, Malin continued. She also said that to encourage new, incremental facilities, the proposal is to give new facilities more credit than existing facilities.

Williams questioned whether the proposal to give a higher credit to new facilities than to existing facilities is fair. In Oregon, private utilities stepped up to the renewable challenge, but now "may have to pay twice" if system benefit charges do not qualify as an eligible expense, she said. "That does not seem like a fair deal", Williams stated.

Chalier said she did not disagree with the proposed incremental requirement, otherwise public power customers pay a benefit to IOUs to offset the state requirement for the system benefit charge, she said. But public customers in Oregon do not pay the system benefit charge, Williams said. However, public customers get some of the benefits (of the system benefit charge?), she said.

Comment noted, Malin responded. She continued going through the document and pointed out that it does not yet have approval from BPA management.

Malin said a number of changes had been made to the definitions section (5.2). Williams asked why BPA proposed to use its preference rate as the avoided cost for full requirements customers and the 2007 Mid-C market prices for all other customers. Malin responded that it was an attempt to accurately capture the avoided costs of the different customer classes. All of the IOUs are building new resources, so it seems they would represent the avoided cost, Williams said.

The $49 per MWh Mid-C price seems high, Williams said, adding that she thought PGE's avoided cost was closer to $43 to $45. The avoided cost would be the avoided cost for anyone building a CT, she added. The $49 does seem high, Carr agreed.

Idaho Power has been talking about an avoided cost of $60 because of high gas prices, Carel DeWinkel (ODOE) pointed out. The gas market is more robust than the electricity market, Williams responded. If you have better numbers, let us know, Malin reiterated. But it's preferable to use posted numbers for avoided costs, she said.
Malin called attention to the fact that "new" resources would only be eligible for credit on one year's worth of estimated energy production, – we don't want to penalize facilities that come on late in the rate period. This is a short 3-year rate period. A credit based on actual production (as currently used) would only benefit those projects energized in the very beginning of the rate period. Paying for one year of avoided costs, regardless of when the project is energized during the rate period gives the utilities more flexibility and will incent new facilities, she added.

Malin pointed out the estimated 2007 costs of new renewable resources used in the proposed revisions to Table 2 and asked for comments/suggestions. She noted that the hydro costs were really only estimates, due to the lack of good cost information.

Malin explained the capacity factor figures on Table 3. We took most of these numbers out of the Council's 5th Power plan, but some are assumptions. If there are better numbers out there, please let us know, she requested.

Malin noted that the draft proposes a $500 per kw credit for PV and $500/40ft2 solar water heater.

Moving back to the definitions section, Malin noted the definition of "environmental attributes." Are you differentiating between green tags on new and those on existing facilities? Williams asked. It seems if you are differentiating between new and existing facilities, you should treat Tags in that same way, she commented.

Malin pointed out that there would need to be a limit on the Renewable Energy Certificates (RECs). RECs from a "new" facility which is claimed under the renewable rate credit option cannot also be claimed. E.g. RECs from new facilities otherwise claimed in the rate credit program cannot be claimed elsewhere in the rate credit program. She continued through the definitions then moved on to other sections of the document.

With regard to Section 5.3, Malin asked if January 1, 2010 would work for the cutoff date to energize a new renewable facility, and pointed out that Section 5.4 requires facilities to be metered. There were no changes in 5.5 and 5.6, she said, and noted that in Section 5.7, she would make clear that the environmental attributes (RECs) from new renewable faciltities claimed elsewhere in the rate credit program could not be used for more than one year of production. With regard to donations (5.11), we deleted a reference to the Bonneville Environmental Foundation because there are now other organizations promoting renewables in the PNW (Oregon Energy Trust, Climate Trust) and there should be no deference given to one organization over the others, Malin said.

In Section 5.12, we deleted some programs that are no longer around and added some new ones, she continued. Malin said she would add mutual fund idea (cooperative wind project, purchasing turbines not energy) to the list and asked for comments on what level of funding this type of investment warranted.

Chalier asked about the reporting standards for renewables, and Ingram said the general reporting requirements are likely to be the same for renewables as they are for conservation. It would be good for us to have the same reporting period for both conservation and renewables, Malin said.

Williams suggested the possibility that people will be working on renewable projects that never deliver. If the project never delivers, would we be required to give the money back? Williams asked. We'd presume that would happen, Ingram responded. If you don't come through, there will be a procedure to give the money back to BPA since it is paid out in anticipation of performance, he added.

Malin repeated that she wanted comments on the draft by June 21, after which she would prepare a more formal policy for rollout to BPA management. She said she would add several items based on the meeting comments, including: Clarifying mutual fund purchases; clarifying that new resources (or their RECs) can only be claimed for one year; add information about the six-month reporting period; address PGE's concern over eligibility of the system benefit charge for the C&RD; clarify what happens when utilities fail to deliver on a C&RD pay out.

We won't be scheduling another renewables focus group meeting right now, Malin wrapped up. Our next meeting topic will be the use of the facilitation funds, she added.

The meeting adjourned at 2:45 p.m.