BONNEVILLE POWER ADMINISTRATION

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April 2002

To BPA customers and citizens of the Pacific Northwest:

Last year, I sent you a series of letters to keep you informed of BPA's financial and business situation. At the time, I outlined steps we were taking to address the challenges of an extraordinary year that included the West Coast energy crisis and severe drought in the Northwest. I promised to keep you informed of important issues in the future. I want to honor that commitment by reviewing our current financial situation and explaining our best estimate of where we expect BPA's wholesale power rates to go over the next 18 months. I've also included a short update on the upcoming transmission rate case.

On April 1, BPA implemented a 4 percent rate decrease on its total wholesale power rate. However, if current market forecasts hold, in October you'll most likely see the power rate return to the pre-April level or slightly above for about the following 12 months. I am disappointed because I had hoped to see a downward trend in rates begin as early as this year.

I realize this fall and rise in power rates is confusing, particularly since wholesale power prices have fallen in the past few months. I hope the following information will give you a general idea of what is happening. More specific information will be available to those who would like to understand our circumstances in more detail.

April adjustment vs. October adjustment

Prior to last year, our policy had been to provide fixed power rates for a five-year period so that our customers would know what to expect. But, with the incredible price volatility we saw in West Coast power markets last year, it became clear we would need to collect substantial amounts of money for financial reserves if we were to stick with fixed rates. Consequently, BPA and its customers worked together to develop rate adjustment clauses that would trigger only when necessary, rather than collecting money ahead of the need. We have three different rate adjustment clauses (described in a sidebar on page 6) that trigger at different times and for different reasons.

In short, our rates went down in April because we made an adjustment that reflected only the lower cost of purchasing firm power to serve our customers. The October adjustment, on the other hand, will reflect our overall financial situation, and that's when we are likely to see a rate rebound.

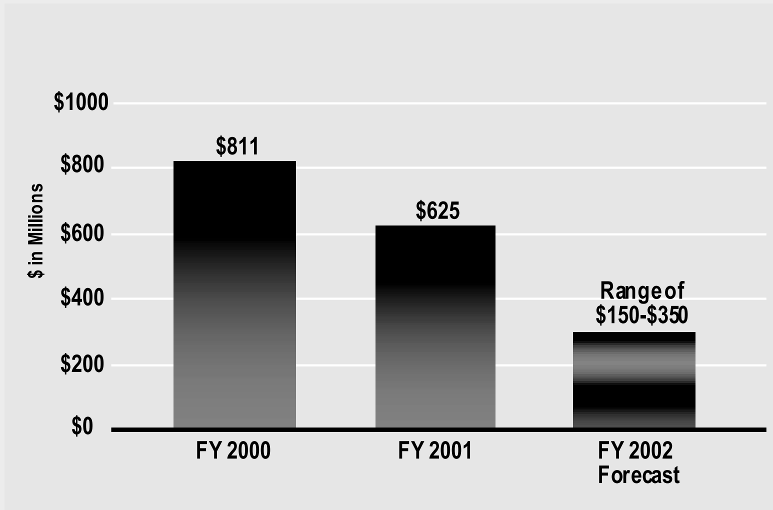
Many complex factors contribute to our rate levels. The biggest is our worsening financial situation due to a significant drop in net revenues this year. This is largely a result of lower-than-average seasonal surplus hydropower, combined with unexpectedly low market prices for this power. This is power that is available when water conditions exceed the worst on record. Because we cannot count on this power, we do not use it to serve our firm loads. Instead, we sell it as seasonal surplus when it is available and as water conditions warrant. However, when setting rates, we assume we will generate revenues from these surplus sales. In normal water years and under normal market conditions, BPA earns significant revenues from sales of this surplus. These revenues help keep our firm power rates down. But, unfortunately, this year we are not realizing the significant revenues from seasonal surplus that we forecast under average water conditions last June when we set rates. Mostly as a result of this, we expect to lose money for the second year in a row.

There are many complex factors that affect power rate levels, but the four primary factors are outlined below.

Primary factors influencing our rate levels

Power market prices: Last year when we were exposed to a high-priced market, we took actions to assure we would be a net short-term seller of power and not a net purchaser this year, even under severe water conditions. As noted above, the lower-than-average hydro and low prices we are getting for our seasonal surplus power are the biggest factor in the changed expectations for our

BPA Financial Reserves



BPA drew down its financial resources by $186 million in FY 2001. This decline was largely due to unanticipated power purchase costs during times of extremely volatile market prices and near-record low streamflows. The current forecast of reserves for the end of FY 2002 shows an additional drop to a range of $150 to $350 million.

Why rates went down in April

April's downward adjustment in power rates does not reflect BPA's overall financial situation. The decrease in the combined power rate is a result of a reduction in the load-based cost recovery adjustment clause (LB CRAC). This adjustment reflects only the lower cost of acquiring the augmentation resource – the amount of firm power or firm load reduction that we bought to serve our customers who asked for 3,000 megawatts more than federal resources could provide.

About half of the dollars we collect from the load-based CRAC go back to our customers whose loads BPA bought down. These include public utilities, investor-owned utilities for their residential exchange customers and the direct-service industries to pay their employees during the periods of their load buydowns. In addition, we will refund approximately $11 million to our customers. This refund represents a true-up between BPA's projected power purchase costs and the actual costs during the first quarter of this fiscal year (October through December).

financial condition. This is the area where we've taken the biggest hit this year compared against our forecasts.

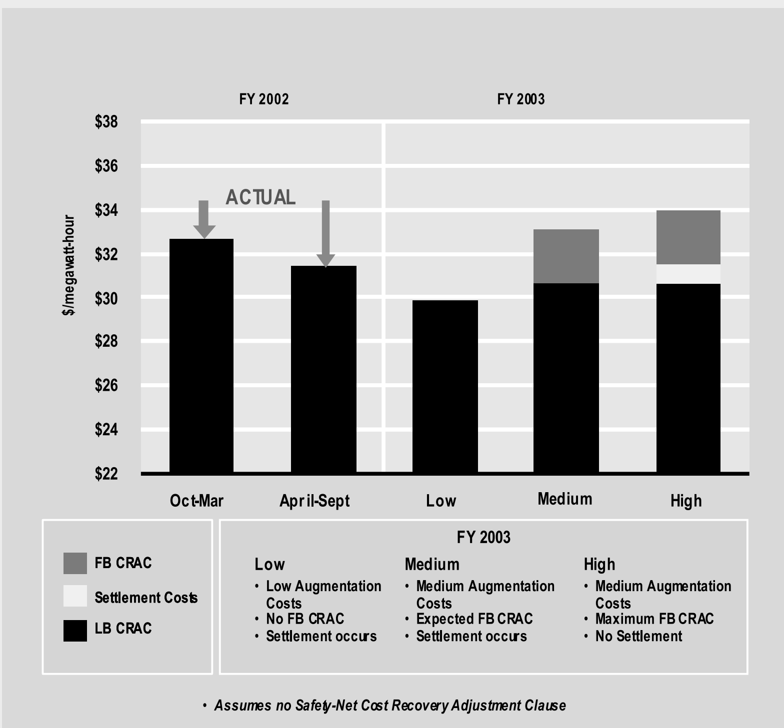
When we completed the rate case last June, we expected this year's surplus power prices to average around $55 a megawatt-hour. In fact, this was a conservative estimate since it was well below the extreme prices we had been experiencing. But market prices have continued to drop, going as low as $20 per megawatt-hour. As a result of lower prices and reduced hydro system output, we are seeing a shortfall of approximately $460 million in net surplus power revenue this year below rate case projections.

This is the most significant driver of our overall financial situation and of our October rate adjustment. While we believe we have a high probability of making our full U.S. Treasury payment this year, we expect to use a substantial portion of our remaining financial reserves as a result of net revenue losses in 2002. This will likely trigger a rate adjustment clause to ensure we have adequate cash to operate the system and make our 2003 Treasury payment.

Power augmentation costs: This is the cost of buying power in the market to meet firm customer requirements that exceed our firm resources. Two years ago, we responded to regional demands for power and committed to provide approximately 3,000 average megawatts more than our firm resource base could produce. To meet regional needs, we then entered into a number of agreements to bring our supply and demand into balance. These included agreements to purchase power on the wholesale market, which is known as augmentation. They also included agreements in which customers agreed to reduce the demand they put on BPA, known as load buydowns.

Some of the load buydown agreements will expire soon. As market prices have dropped, the costs of replacing these agreements with market purchases have dropped somewhat as well – hence

Average Combined PF Rate



Although BPA's combined wholesale power rate declined by about 4 percent on April 1, current estimates for next year's rate show a return to roughly the level of the first half of FY 2002. Next year's rate will depend on the cost of augmentation purchases, the outcome of settlement discussions in a lawsuit by some public utilities over the Residential Exchange Settlement Agreement and whether or not the financial-based cost recovery adjustment clause is needed.

the rate decrease in April. As more buydown agreements expire and are replaced with purchases at lower prices, we should see lower augmentation costs in the October rate adjustment. This will help mitigate the financial pressures that are pushing rates in the opposite direction, as described above.

However, an important uncertainty BPA faces is the amount of load we will be obligated to serve and the timing of Northwest aluminum plants returning to production. Given current low world aluminum prices, it is doubtful that much of the region's plant capacity will be able to operate at currently contracted levels. This creates a critical uncertainty for us as we attempt to arrange power supply to meet our contractual commitments to these plants for 2003 and beyond.

We expect our augmentation costs to go down because we expect market rates to remain lower through the time we will be making power supply decisions. But, if market rates go up and we were to get higher direct-service industry loads, then we could see an increase in augmentation costs.

Hydro conditions: Water is a perennial uncertainty in the Northwest. The impacts of last year's drought lingered in the form of low streamflows and last fall's low reservoirs. In addition, the January to July runoff forecast is running a bit below normal. Together the effect has been to reduce hydropower output by about 450 average megawatts in the current year. If this holds up, energy production from the hydro system this year would be further reduced from the average conditions assumed when we set rates.

Overall program costs: These do not include costs of power augmentation, costs related to providing other Subscription benefits and fixed costs. They do include operation and maintenance costs. Of the four primary factors influencing rates, managing program costs is where we have the greatest control.

In 1996, a blue ribbon panel of business leaders made recommendations in a Comprehensive Review of BPA's cost structure. We adopted many of their recommendations for aggressive program cost targets in our 2002-2006 wholesale power

Net Surplus Power Revenues for FY 2002

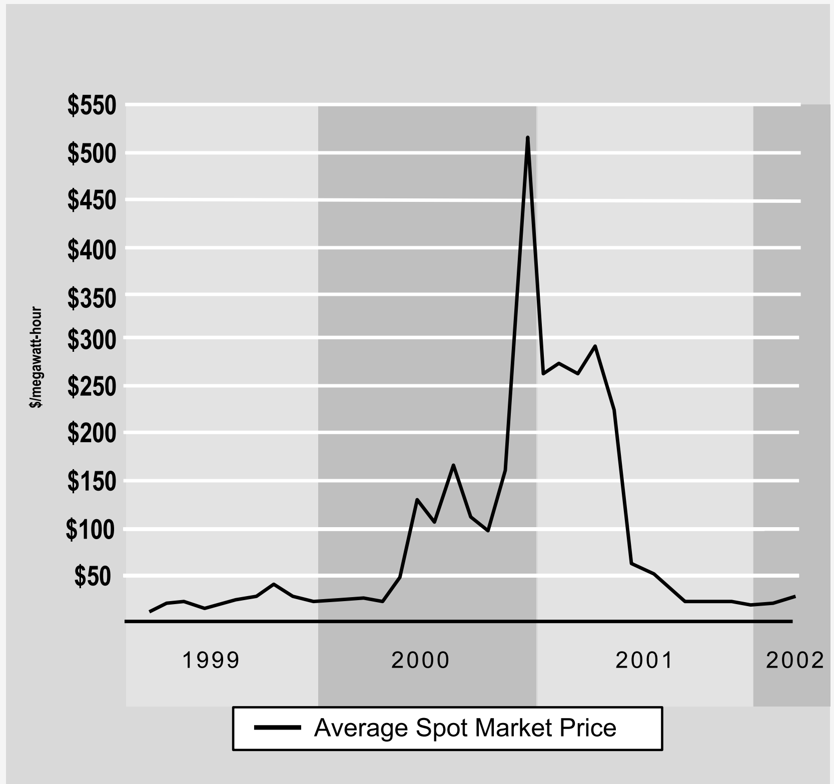
From June 2001 to the current forecast, net surplus revenues dropped approximately $360 million due to market prices. The loss of generation contributes another approximately $100 million drop for a combined effect on net surplus revenue of roughly $460 million. These financial estimates fluctuate dramatically with changes to market price and streamflow forecasts. Stay tuned.

rate structure. While some areas are over the targets and others are under, on the whole we are on schedule to meet the program cost targets for this year. This year's financial difficulties are not due to cost excursions from the Comprehensive Review recommendations.

With that said, we do have some cost increases in areas outside the scope of the Comprehensive Review. For example, we have made investments that have increased the generating capability of our assets, but these costs should be offset by associated revenue increases. In addition, our costs for providing benefits to residential and small farm customers of the investor-owned utilities increased when we settled with them last year.

Market Price of Power

(Based on the Dow Jones Mid-Columbia Index)



Since the first part of 2000, actual wholesale power prices have exhibited significant volatility, reaching a peak of just over $500 per megawatt-hour in December 2000. Prices then settled into the $200 per megawatt-hour range for the spring of 2001, before starting a decline to the current prices that range from $20 to $30 per megawatt-hour.

There are other complex factors that influence our rates, such as the amount of credits that BPA receives from the U.S. Treasury for fish and wildlife investments beyond the ratepayer obligation. Another factor that could influence rates is the outcome of a lawsuit between some public utilities and two investor-owned utilities over their residential exchange agreement. If this litigation is settled in a timely manner, it could reduce our costs by about $50 million next year, which would translate to a rate reduction. These issues are too long to go into in detail here, but that information will be available to our customers and stakeholders. Overall, however, the four factors outlined above are the key drivers of our rate levels and should give you a conceptual sense of what is happening.

There is also some positive news that should be noted. Last year, we put an extraordinarily large rate increase in place. With your help, we took decisive action. As a result, we have been able to retain our high bond rating while many other utilities on the West Coast have been downgraded. In addition, we are currently in the market accomplishing additional refinancings of the Energy Northwest (nuclear) debt that will reduce costs for ratepayers both in the short and long term. The net present value savings of these refinancings for Pacific Northwest ratepayers is about $48 million.

Our commitment to cost management

When we finalized rates last June, we faced cost increases for items such as the residential exchange program that we expected to cover with seasonal surplus power revenues. With revenues from this source down, the Power Business Line is managing its other program costs to try to compensate for this shortfall. The Transmission Business Line also is focusing on cost management in order to help our overall financial situation. BPA's corporate and shared services units are managing costs as well.

As we develop new cost information for the outyear projections, the initial look leads us to believe that we will face some difficult tradeoffs. We will be developing our cost picture further and sharing it with the region. Meanwhile, we are taking the following steps.

- We will continue striving to hold to the aggressive targets for net program expenses embedded in the power rate case for this year.
- We are actively addressing our program costs for 2003 and plan to engage our customers and others in a review of those costs and opportunities to boost revenues.
- Pending completion of our review of next year's costs, we are making no new long-term commitments, except those absolutely necessary to keep our infrastructure program on track.

We are confident that, through managing the costs of our programs, we will be able to main-

A primer on the cost recovery clauses

In setting wholesale power rates for 2002-2006, we anticipated a period of extreme volatility and, at our customers' suggestion, instituted a system of three cost recovery adjustment clauses (CRACs). This system allowed BPA to set its base rate for the five-year period as low as possible while maintaining flexibility to respond to highly volatile conditions. The alternative would have been to set base rates much higher to ensure coverage of all contingencies. Instead, the CRACs cover only those contingencies that actually occur. Most important, the CRACs ensure BPA's financial health and ability to meet its obligations to the U.S. Treasury.

Load-based Cost Recovery Adjustment Clause (LB CRAC): This allows BPA to adjust rates every six months, beginning Oct. 1, 2001, to recover the cost of purchasing augmentation power – that is, firm power BPA needs to serve its firm loads beyond what the federal system can provide.

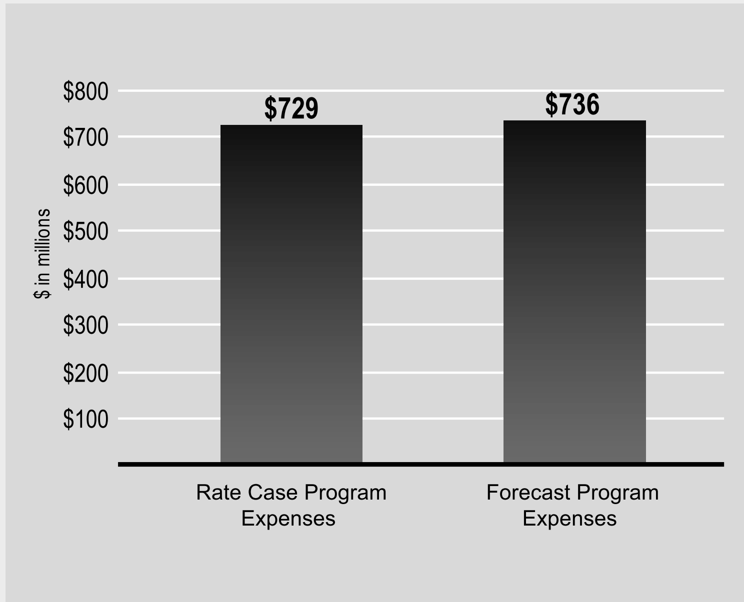
Financial-based Cost Recovery Adjustment Clause (FB CRAC): This allows BPA to make a temporary annual adjustment to the base rate if BPA's Power Business Line's accumulated net revenues fall below a preset threshold. It can trigger independently of the load-based CRAC. The single largest influence is the market for BPA's seasonal surplus power sales.

Safety-net Cost Recovery Adjustment Clause (SN CRAC): The safety net is the last resort. It would go into effect only if there is less than a 50 percent probability of making our annual payment to the U.S. Treasury or if a Treasury payment is missed. Failure to make this payment exposes the region to criticism that the taxpayers are subsidizing us. This would threaten keeping the benefits of the federal hydropower system within the Northwest.

tain a high probability of meeting our Treasury payment this fiscal year.

One thing we do not expect to do is declare a power system emergency to modify fish operations required under the Endangered Species Act. Our difficult financial circumstances have raised the question of whether we would declare such an emergency in order to reduce our fish costs. The current situation is very different from last year. While we are in difficult financial circumstances, last year we were confronting a significant problem with reliability that threatened human health and safety. The chances of a reliability problem of similar magnitude this year are extremely remote.

Program Expenses for FY 2002



The current forecast of the Power Business Line's FY 2002 total program costs, after accounting for any resulting revenues, is about $7 million higher than anticipated in the 2002 Power Rate Case. This category does not include costs of meeting Subscription loads that are generally covered by the load-based cost recovery adjustment clause nor of the residential exchange settlement. The fixed costs related to capital investments also are not included.

The infrastructure work will move forward

At the same time we are trying to aggressively manage to our program targets, we are making significant investments in federal generation, transmission and conservation. In order to support this investment program, we are increasing our staffing. Not unreasonably, this has raised some questions over whether we should increase infrastructure investment and staffing given our financial circumstances. However, despite these circumstances, I strongly believe these actions are prudent. If we were to back away from this effort, we would significantly increase the risk that the region will experience more of the price and reliability shocks that the West Coast experienced in 2000 and 2001. Investments to assure a reliable supply and delivery of power are critical to the Northwest's economic recovery and expansion.

Also, because a significant portion of the costs of this investment and increased staffing are capitalized, they have a lesser impact on our current rates situation. In addition, given the historically low interest rates we are now experiencing, this is an excellent time to be making infrastructure investments. As we develop our cost management strategy, we are trying to assure we keep rates as low as possible in the near term without sacrificing the energy infrastructure we need to keep rates low and reliability high in the long term.

Transmission rate case coming up

While I have principally addressed power rates, I also want to use this opportunity to give you a heads-up on transmission rates. Transmission is on a separate rate schedule from BPA's power rates. Where power rates were set for a five-year period from 2002 through 2006, transmission rates were set for a two-year period from 2002 through 2003. Therefore, the Transmission Business Line anticipates beginning a new rate case this fall. In anticipation of its upcoming rate case, Transmission will conduct a public process to review program levels. We expect this program review process to kick off in May.

Your input is welcomed

We know our rates are important to the region. As always, your ideas and input are valuable. Apart from the transmission rate case, both the Power and Transmission business lines will be conducting informal meetings over the next few months with customers and other stakeholders to share information about our financial picture and cost and revenue management progress. Whether or not you are part of these meetings, we will do our best to keep you informed of our financial situation and its impacts on rates through other venues such as these letters.

Ultimately, we have a responsibility established in law to set our rates as low as possible consistent with sound business practice. We are committed to working with you to search for answers that meet this test.

Sincerely,

Stephen J. Wright

Administrator