BONNEVILLE POWER ADMINISTRATION

P.O. Box 3621
Portland, Oregon 97208-3621

November 22, 2002

To BPA customers, tribes, constituents and interested parties:

The last two years have been particularly challenging for the Bonneville Power Administration. We've seen our cash reserves shrink dramatically, and, without a significant course correction, we could face continued losses for the remainder of the rate period. Last July, in letters to the region, Power Business Line Senior Vice President Paul Norman and I laid out the financial situation and invited your input on how we should meet these financial challenges. Following that, we hosted public meetings on our financial choices throughout the region and sought comment from Northwest citizens.

This letter describes what we heard in those conversations and outlines the actions we are taking to achieve financial stability so we can hold the line on rates and honor our public responsibilities. It also details the significant uncertainties we face.

First, the conclusions

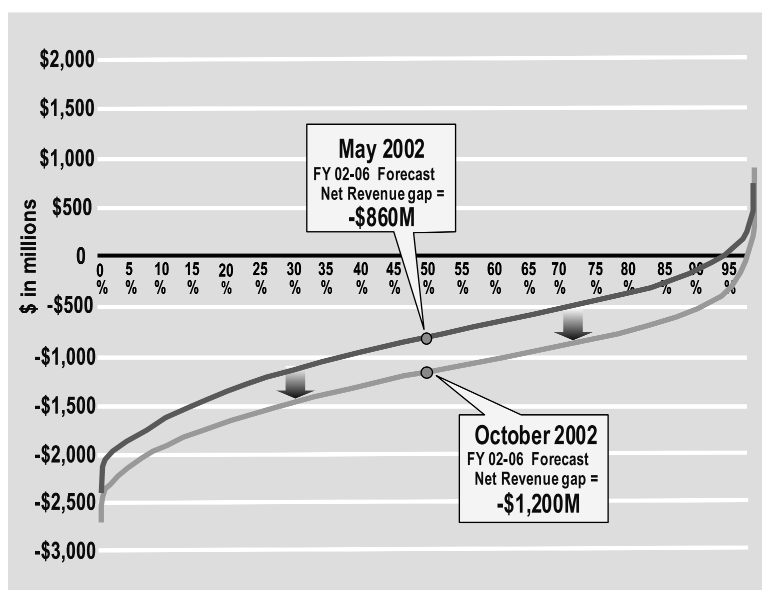
After six months of regional discussions and detailed looks at our finances, we have learned a lot. Here, briefly, are six conclusions we have reached.

First, the financial gap between our revenues and expenses is wider than we thought last summer. We had been looking at an $860 million gap between projected costs and revenues over the 2002-2006 rate period. With continued low market prices for our surplus, that gap has grown to $1.2 billion – on an expected value basis *(see figure 1 describing how and why the gap has grown)*.

Second, this financial picture assumes BPA will see a substantial upturn in revenues from the secondary (surplus power) market. Our revenue forecasts are based on a reasonable set of assumptions but still represent substantially more net secondary revenue than BPA has generated historically *(see figure 2)*. If these revenues do not materialize because of poor hydro conditions or low market prices, our financial gap will grow.

Figure 1

Seeking to Break Even
2002-2006 Net Revenue Gap



Between May and August 2002, the forecast of BPA's expenses vs. revenues for 2002-2006 showed a widening gap – going from an expected loss of $860 million to $1.2 billion over the rate period. The forecast is based on a range of water conditions and market prices. This decline in BPA's financial condition resulted from sustained low market prices, an updated hydro energy forecast for 2002-2004, and the uncertainty surrounding some take-or-pay contracts.

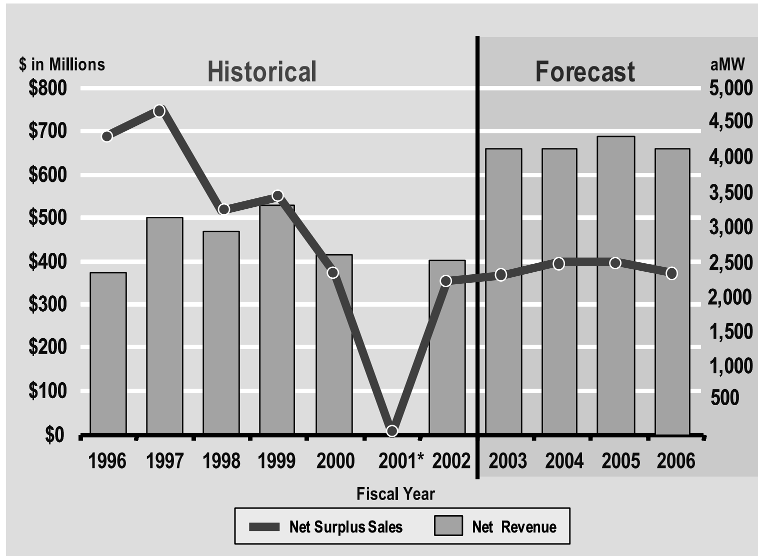
Why net secondary revenues are key

One myth that has grown up about BPA's financial difficulties is that BPA's primary problem is that it entered into high priced contracts for firm (nonsurplus) power and is now reselling that power at low prices. This is not true. The contracts BPA entered into to augment the 8,000 average megawatts of firm power capability of the federal base system averaged $35 a megawatt-hour, a modestly priced portfolio in today's long-term firm power markets. BPA's rates as set in October 2001 adequately cover these costs.

While BPA's loads and resources never match perfectly, in general we forecast a firm load/resource balance for the remainder of the rate period (although there could be some surpluses if industrial loads were to stay down). There are some contracts we would like to modify, but this is not the fundamental driver of our financial problems.

Figure 2

The Critical Uncertainty
Net Secondary Revenue



Projections of net revenues from sales of seasonal surplus power over the next four years are significantly higher than the levels of actual net revenue from such sales over the past six years, even though the projected amount of net surplus sales is always based on average water. The assumed increase from FY 2002 to FY 2003 alone is nearly 50 percent. This increase is primarily due to market fundamentals, especially rising natural gas prices, that point to higher electricity prices for FY 2003-2006.

** In FY 2001 there were no net surplus sales due to the drought.*

The primary cause of BPA's present financial picture is that we were too optimistic with respect to trying to satisfy the region's desires for shares in the value of the federal system *(see box on why BPA's rates increased)*. This optimism grew out of the late 1990s when prices in the secondary markets increased dramatically while water conditions were above average.

We projected, and still do, that BPA's net secondary revenues from seasonal surplus power will increase substantially over historical levels across the 2002-2006 power rate period. But, so far, our experience in the first year is closer to historic levels.

Net secondary revenues are a function of weather (precipitation to feed the hydro system) and market prices. Under most conditions, the generating capability of the Federal Columbia River Power System exceeds BPA's firm loads, and the agency has surplus power to sell. These surplus sales are an important source of revenue and help keep rates down. BPA sells its surplus energy to a variety of customers, including investor-owned utilities, power marketers and other public agencies. Sales to California, which often has higher electricity prices than the Pacific Northwest, also are an important component of BPA's secondary sales revenues.

Net secondary sales revenues often provide roughly 20-25 percent of BPA's total revenues. However, the contribution of secondary revenues to BPA's bottom line and resulting rate structure can change considerably from year to year. The volatility of electricity prices and the huge year-to-year swings in runoff on the Columbia River conspire to create tremendous uncertainty. While BPA's forecasts are well thought through and reasonable, they are still nothing more than forecasts of factors for which there is extreme variability, particularly with respect to short-term outcomes. The key question now is whether BPA's net secondary revenues will move to the forecast level or whether they are going to remain low. If the latter happens, the financial stresses will be even worse than expected.

Third, to date, we have $350 million of commitments (expense reductions, deferrals and other actions) in place that will help close the revenue-expense gap or otherwise aid our ability to pay the U.S. Treasury on time *(see table on page 4)*. Much of this has come from reductions in BPA's internal operating costs as a result of our new target aimed at keeping BPA's internal power-related costs as close to 2001 levels as possible through 2006.

Fourth, despite this effort, we still need significant additional cost savings across the remainder of the rate period if we are to have a chance of keeping rates flat. We have identified and are working to secure over $500 million in additional expense reductions, deferrals and other actions.

Fifth, at this time, we have not hit the condition that would trigger another rate increase (the safety net cost-recovery adjustment clause)[1] in order to deal with BPA's financial condition in 2003. But it is an extremely close call, and it won't take much to push us into that condition. We will need to closely monitor streamflows and markets affecting net secondary revenues, as well as our ability to realize additional savings. We will revisit a decision about whether or not to trigger the safety net adjustment after the first of the year.

Why BPA rates have increased

In October 2001, BPA implemented a 46 percent wholesale power rate increase. Since then, rates have stayed at this level, with small adjustments both up and down. This level is primarily the result of major increases in the amount of public benefits BPA is providing to the region. These benefits include:

- Meeting customers' need for 3,000 average megawatts of power beyond what the federal base system could provide. To put this in perspective, total growth in regional demand for electricity for the entire previous decade was 2,500 average megawatts. To serve this need, we augmented the federal base system with purchased power and load buydowns. This meant buying power at a time when West Coast firm power supplies were tight. This load had to be served by someone and would have shown up in consumers' bills whether or not BPA served it. In fact, BPA's costs for augmentation purchases – averaging $35 per megawatt-hour – still look reasonable. But the sheer volume of purchases added significant costs.
- Increasing the financial benefits flowing from BPA to residential and small-farm customers served by investor-owned utilities. Payments to these utilities increased from $70 million in 2001 to about $400 million a year, greatly reducing the need for rate increases in some utilities' service areas. Over the five-year rate period, these payments will total over $2 billion.
- Increasing fish and wildlife spending by nearly $100 million a year over pre-2002 levels.
- Increasing conservation and renewable resource spending modestly to support system augmentation needs.
- Rising costs of operating and maintaining the hydro system and the Columbia Generating Station nuclear plant to assure planned availability and high system reliability and safety.

As expenses were increasing, revenues were decreasing. In 2001, BPA lost $300 million[2] after a severe drought left us with virtually no inventory to sell into secondary markets and, in fact, caused us to purchase power during the West Coast energy crisis when market prices for wholesale electricity soared. BPA has continued to lose money – another $300 million in 2002. We began that year with an inventory shortfall due to the previous year's drought, and, when we finally had surplus power to sell, market prices had dropped precipitously and then stayed low. Through much of 2002, wholesale power prices often fell to single digits and averaged in the low $20s per megawatt-hour – a stark contrast to the $200 per megawatt-hour and higher prices seen as late as June 2001.

[1] A safety-net cost recovery adjustment clause to adjust rates goes into effect when BPA has a less than 50 percent probability of making its annual U.S. Treasury payment or if a Treasury payment is missed within the current fiscal year.

[2] BPA used over $200 million from a contingency fund in 2001 to cover additional losses.

Sixth, most importantly, it can be reasonably argued that today the BPA system is financially overcommitted. If the system cannot generate net secondary revenues substantially in excess of what's been achieved historically, the problem will be worse. BPA and all those who get benefits from this system are going to be struggling to get expenses in line with revenues for the remaining four years of this rate period. We will also need to be vigilant on how we structure our commitments and costs for post-2006.

What we heard from you

Confronted with two years of an eroding financial condition *(see box on page 3 on why BPA rates have increased)*, we asked for your help. We asked you to evaluate the choices that could best preserve the fundamental benefits the Federal Columbia River Power System provides that you believe are most important. Those benefits range from low-cost reliable power to contributions to our environment and sustainability – energy efficiency, renewable energy resources and fish and wildlife recovery.

In a perfect world, we would strive to enhance all of these benefits. But now is not a perfect time. With shrinking financial resources, we needed your input to help us set priorities so that we can strike the balance that will preserve all the benefits of the federal system for the long term and deliver the greatest value with limited resources in the near term.

During the past few months, my colleagues and I traveled throughout the region. We heard powerful stories. In Umatilla, I met a school official who told me that, because of increasing electricity costs, schools have had to lay off teachers and maintenance staff. I met a fourth generation grain farmer who may lose his farm. In Snohomish, the utility staff described the distress of dealing with people who can't pay bills. The number of power "shut offs" is up more than 50 percent.

The hardest hit are the unemployed. Businesses, large and small, have cut back. This region has suffered more than any other part of the country in the current recession.

Industry representatives described how the Pacific Northwest is losing its competitive advantage. It seems hard to believe in a region famed for its cheap electricity, but the most recent Energy Information Administration data suggest that industrial electricity rates in the Northwest are now somewhere in the middle of national prices. Many manufacturers are finding that their operations are at risk because of increased electricity costs.

I also heard powerful stories from advocates of our programs for fish recovery, renewables and energy efficiency. They point out the high value of these programs and the need to maintain the momentum. Many wanted us to go beyond maintaining, and to provide even stronger support for these programs. They stressed the long-term benefits and the need to build a sustainable future.

Closing the financial gap

As we talked to people, we presented an array of financial choices and asked for comment on a number of approaches to restoring BPA's financial

Expense Reductions, Expense Deferrals and Other Actions

	FY 2003-2006 ($ million)
Expense Reductions	
PBL Internal Operations	$107
Agency Internal Operations Assigned to Power	30
Energy Web	4
Conservation Augmentation	13
Corps/Reclamation	20
Columbia Generating Station (CGS)	15
Incentive Payments (Corps/Reclamation/ENW)	24
Renewables	4
Other	4
Subtotal	**$221**
Expense Deferrals	
CGS Fuel Strategy	$37
CGS Condenser Tube Replacement	35
Subtotal	**$72**
Other Actions	
Energy Northwest Bond Reserve Fund Free-up	$56
Subtotal	**$56**
TOTAL	**$350**

Numbers do not add precisely due to rounding.

stability. These included raising rates, reducing expenses beyond the levels reported in July, taking more risks with our Treasury payment and using cash management tools to move some costs into the future.

An overwhelming message was that cost control is a key part of the solution. In community after community, commenters urged a strong focus on cutting costs wherever possible.

We concluded that our immediate focus must be on restoring BPA's financial health to assure a stable provision of public benefits, which includes low cost power. We intend to fight hard to hold the line on rates, primarily by seeking ways to accomplish our objectives in a more cost-effective manner.

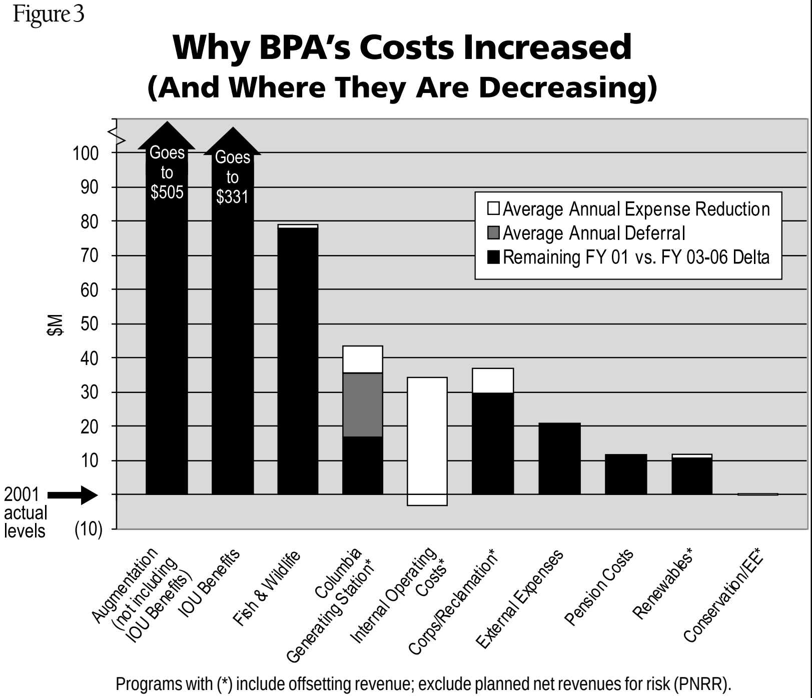
The severity of the financial situation and the need for action is such that we will have to employ a combination of actions. But, by far, our biggest effort has been and continues to be cost containment. We have scrutinized all of our expenses. We have gone to our employees, to our federal partners, to investor-owned utilities, to Energy Northwest, to the Northwest Power Planning Council and to others to seek more expense savings.

The result is that we have identified $350 million in expense savings, expense deferrals and other actions. We believe these savings are secured for the remainder of the rate period.

Much of this effort – about $140 million of the savings – has focused on holding the line on BPA's internal operating costs. We have made reductions across the board.

These included placing a moratorium on outside hires with limited exceptions; reducing budgets for employee awards, travel and training; cutting contractors and materials supplies; reducing research and development efforts; offering early retirement; and introducing a stringent management review process for new financial commitments. We also removed dollars from our budgets that would have been used to develop a scheduling coordinator for a regional transmission organization assuming that, if parties want this service, they will pay for it.

Figure 3



This picture displays BPA's average annual cost increases for 2003-2006 compared to FY 2001. The biggest cost drivers in BPA's current power rates are power augmentation (cost of acquiring resources beyond the capability of BPA's resource base), benefits to residential and small-farm consumers of investor-owned utilities, and programs that benefit fish and wildlife. As a result of the financial choices process, power-related internal operating costs have been reduced to below 2001 levels.

These and other savings will keep BPA's annual power-related internal costs to around 2001 levels through 2006. It will be tough, but we believe we can achieve this goal.

Our generation partners – Energy Northwest, the Corps of Engineers and the Bureau of Reclamation – have all provided substantial cost reductions and deferrals from their planned budgets as well.

Balancing public responsibilities

Success in generating cost savings, however, has impacts and tradeoffs. We need to set priorities, but we are committed to respond in a socially responsible way.

We will continue to work toward a sustainable energy efficiency future, and we intend to meet the Northwest Power Planning Council's target for conservation acquisition. Based on recent experience, we believe we can hit that target at costs significantly below the cost of historic conservation acquisitions if we stay on track with our conservation augmentation program. Some Energy Web research and development efforts will continue, but at substantially reduced levels, as we look for ways to leverage our funding with other regional partners.

We will continue to exert leadership and promote development of cost-effective renewable energy resources but will focus more on facilitating purchases of renewable generation by others than on a BPA-only acquisition program. In all cases, we will continue to press ourselves and our partners to find ways to be more efficient.

These are not all good decisions for the long term, but they reflect our view that near-term rate considerations have taken on higher priorities.

The $350 million in savings, deferrals and other actions is a good start, but we will need to do better if we are to achieve stable rates. We are continuing to pursue expense reductions in other areas that are not yet certain. The potential additional savings in these other areas could be in excess of $500 million. But the remaining cost cuts, deferrals or other actions will take cooperative efforts on the part of many parties in the region. As in the West Coast energy crisis, collaboration will be the key to achieving stability.

For example, we are exploring with other federal agencies and the region the potential for modifications in hydro system measures that would protect fish equally well but more efficiently and at lower expense. We are encouraging investor-owned and public utilities to settle litigation that would avoid $200 million in power augmentation costs. A benchmarking study could lead to further cost reductions at the Columbia Generating Station, although we are committed to not compromising safety or reliability. Renegotiating certain power contracts also could lead to savings.

Risk and other financial tools

In addition to intensified cost management, we are taking some increased risk with our Treasury payment. We estimate that our probability of Treasury repayment for FY 2003 has dropped from the level targeted in our last power rate case but, for now, is above the level that would trigger a safety net cost recovery adjustment. However, that number is very sensitive to water and market conditions and could go up or down. We are seeking to improve our Treasury payment probability, but, unless there is a dramatic increase in net secondary revenues, it is unlikely to get back to historic levels during this rate period.

We also have other tools. For example, Energy Northwest has agreed to defer some fuel purchases and the replacement of a condenser for Columbia Generating Station. We are also pursuing an agreement with our investor-owned utility customers that will allow us to postpone payment of approximately $55 million due in 2003.

There are additional opportunities for postponing costs, but this tool must be used judiciously. To the extent possible, we want to avoid shifting costs to future years. We do not believe it is good public policy to mortgage the region's future. Furthermore, given our need for infrastructure investments and opportunities for refinancing debt at today's low interest rates, it would be imprudent to jeopardize our credit ratings by overly relying on financial cost shifting.

There are important cost reductions and cost management tools that can be achieved through restructuring the Energy Northwest debt. Maintaining a high bond rating is critical to realizing these benefits, and this can be a challenge given the current state of the electricity industry.

Facing significant uncertainties

The analysis of the $1.2 billion gap between revenues and expenses assumes an approximate 10 percent rate decrease from the 2002 level in years 2004-2006. If, instead, we assume flat rates across those years, the gap is reduced by about

$330 million. Together with the expense and deferrals savings that we believe we have achieved so far, this still leaves more than $500 million to close the $1.2 billion gap. But achieving $500 million more in savings still would give us only a 50/50 probability of financially breaking even through this rate period.

Will all the actions we are taking avert another rate increase? We hope so, but nature (rainfall) and the power markets will have a lot to say in that matter. The savings we have achieved and continue to work for will go a long way toward helping us recover our financial health.

Obviously cost cutting and cost management tools alone won't determine our financial fate. We are dealing with variables that are highly unpredictable. The key factor, far and above anything else, will be net secondary revenues from our surplus power sales *(see box on page 2)*.

There are good reasons why the revenue estimate for this coming year is reasonable and why there should be an improvement in 2003. But forecasting water and electricity markets is still an imperfect science. There is huge uncertainty about the amount of precipitation we'll see the next year and for the remainder of the rate period. If the water or market prices are low this year, we're likely to lose money again.

If the secondary revenue forecast is too optimistic on any sort of sustained basis, then the benefits BPA is providing the region cannot be sustained without pushing costs into the future or raising rates. In particular, if the economy remains anemic, this could continue to depress market prices for electricity, which would affect our financial situation.

Another area of uncertainty is the potential for uncollectible liquidated damages from direct-service industries. These industries signed take-or-pay contracts that stipulated that, if they did not use the power, they would make BPA whole for any losses BPA would incur if it has to resell the power. Already, a court has approved one industry's request to terminate its contract while it is in bankruptcy proceedings (BPA has filed claims to recover damages). If the market takes a downward turn again, this could be a factor that could figure into a rate increase.

Looking ahead

I have laid out these issues to present the situation we face as clearly as possible. After the first of the year, we're going to have a far better picture of water and market conditions for 2003, and thus a better handle on net secondary revenues for this fiscal year. We plan to make a further report to you at that time. In the meantime, we are working aggressively toward the goal of keeping rates approximately where they are. We don't know if we can accomplish this, given how much is outside our control. But we are going to make every effort to achieve this goal.

Sincerely,

Stephen J. Wright
Administrator and Chief Executive Officer