**Department of Energy**

Bonneville Power Administration
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EXECUTIVE OFFICE

April 18, 2003

In reply refer to: P-6

**To our customers and Northwest citizens:**

In the past three years, the Bonneville Power Administration (BPA) has gone from an agency that was financially healthy to one that is clearly in trouble. We are well aware that many of our regional constituents believe BPA is not meeting the expectations we created when we set rates and signed new power contracts in 2000. Because we want to ensure we are managing the region's federal resources optimally, we conducted a careful and sometimes uncomfortably candid examination of the events that led up to the present situation. The result is the enclosed report to the region that was developed to answer these key questions:

- Why are BPA costs and rates so much higher now than they were in 2001?
- Why is BPA losing money after putting in place large rate increases?
- What lessons can be learned from this that should translate into future actions?

Some of the things that happened to us were outside our control, such as a serious drought, the West Coast energy crisis and, most recently, a dry fall and winter. But some things we did to ourselves. It is only through exploring this history that we can hope to improve in the future. As we went through the process of examination, some key takeaways emerged.

1. The 2001 drought and the West Coast energy crisis were external factors that substantially damaged the agency financially. The 2001 drought cost BPA approximately $600 million, and low water this past fall and winter is projected to cost about $200 million. The costs associated with 2001 would have been substantially worse if BPA had not declared power system emergencies. The West Coast energy crisis also led to BPA serving more load at a higher price than was forecast, although the financial magnitude of this impact is difficult to quantify.

2. BPA has seen its costs increase by approximately $1 billion annually in the years since 2001. The bulk of this increase, 75 to 80 percent, is due to our decision to serve 3,300 megawatts beyond our resource base. This service was requested by customers and is included in the Subscription contracts signed in 2000.

3. Revenues we had forecast from the sale of seasonal surplus hydropower have not materialized. Most of this was due to assumptions that reflected the spot market in 2001 but now have turned out to be overly optimistic. This has created substantial problems because our program funding commitments assumed we would realize these revenues.

4. The budgeted costs in 2000 of operating our generating assets (Corps of Engineers and Bureau of Reclamation dams and Energy Northwest nuclear plant) and of BPA's internal operations have not been achieved by a substantial margin. This is due to four factors: (1) the original cost estimates were unrealistically optimistic and did not reflect the needs to operate the core assets that create the value of the system; (2) there were not adequate cost management plans internally or with our cost partners to achieve these estimates; (3) the fundamental business model that was assumed to develop the cost estimates was altered (i.e., that BPA would serve only a limited amount of load), and (4) the changing environment created unanticipated costs (security and operational requirements).

5. BPA has several internal process issues that must be improved to provide higher value to the region. Principal among them is our need to substantially improve our risk management systems. Given our size, it has made sense historically for BPA to take on risk. But, with wild price volatility, the level of risk BPA can take on is finite. The primary risks BPA took on were service to 3,300 megawatts of load beyond our resource base and committing to fixed funding based on projections of secondary revenue. A particularly important finding in the report is that BPA’s culture is one in which we seek to find ways to say “yes” to a variety of requests from our stakeholders while also seeking to avoid rate increases. This traditionally has resulted in the agency taking substantial financial risks.

6. While not intended to do so, our decisions have over time led to a lack of equity, with some stakeholders realizing benefit increases and others realizing benefit reductions.

7. We took a number of crucial actions that successfully mitigated what could have been a worse situation. In particular, BPA's purchases and load buydowns to serve the 3,300 megawatts of load beyond our resource base represent a reasonably priced portfolio given the time period in which it was acquired.

8. Even with increased operating costs, the value of the federal system’s core assets (the Federal Base System composed of the federal dams and the Energy Northwest nuclear plant), compared against market purchases, is still substantial. This system, properly managed, can and should provide substantial benefits and increased value for the people of the Pacific Northwest for a very long time.

The enclosed report is long, detailed and not always flattering, but I wanted a candid examination that would allow us to learn truly constructive lessons. We are committed to using these lessons to improve the management of the agency and the Federal Columbia River Power System.

We take this report very seriously and expect it to lead to improvements. We have begun development of an action plan to apply the lessons learned from this experience and to better position us to serve you and the region. We will share this plan with you in the very near future.

Sincerely,

Stephen J. Wright

Stephen J. Wright
Administrator and Chief Executive Officer

# WHAT LED TO THE CURRENT BPA FINANCIAL CRISIS?

## A BPA REPORT TO THE REGION

**April 2003**

BONNEVILLE
POWER ADMINISTRATION

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# What Led to the Current BPA Financial Crisis?
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## Executive Summary

In May of 2000, the Bonneville Power Administration was on a path to sign long-term power sales contracts with an expectation that BPA rates would not be significantly higher than they had been for the previous five years. From 1997 to 2001, BPA's average preference power rates had remained steady at about $22 per megawatt-hour (MWh). During that time, the agency's financial reserves rose from $278 million at the end of 1996 to $625 million at the end of 2001.

But our world began to change that May, and since then we have been on a different path than we'd anticipated. BPA raised rates for 2002 by an average of 43 percent over 2001 levels, and, despite that, we've watched our reserves plummet toward zero. Midway into fiscal year 2003, we and our customers face the specter of another rate increase – possibly in the neighborhood of 15 percent – to restore the agency's financial health.

We have not been alone in facing economic distress. The Northwest economy as a whole is stressed. Industrial loads have been down since the West Coast energy crisis of 2000-2001, and higher electricity prices threaten many companies. Irrigators are faced with shutting down their pumps and letting their fields go fallow or turning to dry-land crops. Individuals are unable to pay their electricity bills and are having their power turned off in record numbers.

To limit the rate increase, BPA has cut back its internal costs and is asking its partners in managing the Federal Columbia River Power System to hold down their costs as well. We have also asked the fish and wildlife managers to limit their spending.

The economic impacts, however, have not been distributed evenly throughout the region. One group of customers made early commitments to continued BPA service and signed what are known as "pre-Subscription" power sales contracts and are paying the same rates now that they did in the previous rate period. The residential and small-farm consumers of investor-owned utilities have seen their benefits rise from $70 million annually to over $400 million annually. These elements are producing significantly different rates between neighboring communities. Additionally, thousands of Northwest aluminum workers have continued to receive paychecks for periods of six months to two years while their smelters have been idled under agreements with BPA. This is at a time when world aluminum prices have been at such low levels that, when combined with higher power prices, it would have been difficult for the smelters to operate.

All this is outlined in the report that follows. We have attempted to provide an analysis that describes what happened between the optimistic outlook we had in early 2000 and today's reality. We have tried to go beneath the events in order to understand why the changes occurred. In describing what happened, we found it useful to describe two different perspectives: one compares BPA's costs during this five-year rate period with costs during the previous rate period, and another compares the current expectations for this five-year rate period with what we expected for this time frame when we set rates in 2001.

We know that merely explaining what happened and why is only the beginning. We need to follow through with the implementation of changes that will improve our long-term results.

## Background

After BPA lost a significant amount of load in 1996 and market prices fell below BPA's rates for several years, our role was re-examined in the late 1990s by the Comprehensive Review of the Northwest Energy System and by BPA's blue-ribbon Cost Review Board. Reports from both reviews envisioned a BPA that sold the federal hydropower under simple contracts that did not service the region's load growth.

The agency adopted that model and began work to "subscribe" customers to the system – that is, offering long-term contracts for power sales. Because BPA's prices were higher than the market at the time, the agency made an effort in 1997 to re-attract the load we had lost through the offer of competitive, fixed rates for a five-year period. A number of utilities – mostly small full-requirements customers – pre-subscribed to BPA's power sales and made an early (and some believed risky) commitment to BPA. As a result, they are still paying about $22/MWh and will continue to pay this rate through 2006.

By the time of BPA's May 2000 rate proposal, the world was changing as the West Coast energy crisis began to unfold and market prices dramatically increased. As all of BPA's customers (public utilities, investor-owned utilities and direct-service industries) found BPA's offer of low five-year fixed power rates attractive in the context of increasing market prices, they turned to BPA to supply more of their post-2001 power supply needs. BPA made key decisions around that time (mid-2000) that put BPA in a different role from that described by the Comprehensive Review and Cost Review. We had signed new power sales contracts for five- and 10-year periods by October 2000 that wound up exceeding the firm power production of the Federal Base System by about 3,300 average megawatts (aMW). We had accomplished some augmentation of our power supply to serve additional loads by that time, but the majority of our power purchases had to be accomplished with only a one-year notice before the new contract period started on Oct. 1, 2001. Because new power supplies had a cost significantly higher than the Federal Base System (and the other costs embedded in our base power rates), our original rate estimates would not be sufficient to recover the costs of serving the higher loads. We worked with our customers in developing a strategy of keeping base rates as low as possible while designing a three-layer series of cost recovery adjustment clauses (CRACs) to respond to potential increases in costs.

As market prices for new power supplies continued to soar, we led an extensive load reduction effort among all customers in an attempt to keep the Load-Based (LB) CRAC as low as possible. As it ended up, we went into the new rate period with a 46 percent LB CRAC over the base rates of $22/MWh in the May 2000 proposal.

In the first two years of the current five-year rate period, BPA has continued to lose money despite the higher rates. This is principally because some costs are higher than we anticipated and because our assumptions about the amount of secondary revenues we expected to receive in extraregional markets have proved too optimistic. We project that we have about $5.3 billion more in costs over the five years than we did in the last rate period. We now expect to receive about $1.4 billion less in revenues than we projected in June 2001 when we established the CRAC mechanisms, and this is compounding the problems we are experiencing on the cost side. The principal drivers behind these changes are described below.

## Expenses

BPA's total costs over the five-year rate period of 2002-2006 are about $5.3 billion higher than they were in the previous rate period. From the perspective of both the costs of the last rate period and the costs estimated by the rate case for the 2002-2006 period, the six largest drivers behind the current rate pressure are as follows:

- The cost of augmenting the Federal Base System – including both power purchases and load reductions – makes up about three-fourths of the increase in costs over the last rate period. This increase in costs of $3.9 billion occurred because BPA assumed responsibility for serving about 3,300 average megawatts (aMW) of load beyond the firm generating capability of the Federal Base System.
- BPA power and financial benefits for the residential and small-farm consumers of investor-owned utilities (IOUs) make up the next category of increases compared to both the last rate period and the costs in the base rates – about $370 million over five years. Including the payments reflected in the augmentation costs above to reduce the IOUs' load on BPA, total benefits flowing to the residential and small-farm consumers are over $400 million per year for the current rate period (or over $2 billion in total) as compared to about $70 million per year over the last rate period.
- Fish and wildlife costs are also up about $370 million over the five-year period compared to the previous rate period. These costs include lost opportunity costs of operating the hydro system for fish mitigation and U.S. Army Corps of Engineers and Bureau of Reclamation reimbursable fish and wildlife program costs. However, fish and wildlife costs are being managed within the budget established in our base rates.
- Compared to 2001, net interest expenses have increased $320 million over five years primarily because of the reduction in our net interest income due to lower cash reserves. Compared to our expectations embedded in our base rates, this category of expenses is up $60 million over the five-year period.
- Federal hydropower costs and Columbia Generating Station costs have increased a total of $160 million over five years compared to 2001 and have increased $267 million compared to our expectation in the rate case. The increase in costs is primarily driven by the need for increased maintenance, capital replacements and increased security.
- Internal operations expenses assigned to BPA's power function can be looked at two ways. From 2003 forward, these costs will be controlled at 2001 levels net of revenue gains from efficiency improvements achieved by these expenditures. Compared to the rate case, however, these net expenses are up by almost $280 million. The rate case assumed they would decline in response to a reduced role for BPA and, in retrospect, had an unrealistic view the level of costs necessary to carry out BPA's power operations in a radically different world of wholesale competition and a separation of our power and transmission functions due to new FERC regulations.

## Revenues

While increased costs have had a substantial impact on rates, revenue shortfalls have also caused BPA's financial condition to erode and put additional pressure on rates. These revenue shortages are attributable to the following causes:

- Lower revenue from secondary power sales due to lower market prices is the major source of our shortfall – a total of $715 million over five years. West Coast power market prices declined rapidly after our new rates were instituted in October 2001. While we anticipated the market price for power to decline over the rate period, we counted on it to stay higher longer than it did. This is particularly significant because the revenue we receive from secondary sales (about 20 to 25 percent of our total revenues) allows us to keep our prices for firm power delivered in the Northwest lower than they would otherwise be.
- The 4(h)(10)(C) and Fish Cost Contingency Fund (FCCF) revenue credits are estimated to run about $300 million less over the five-year period than we assumed when we established the CRAC mechanisms. These credits are provided by the U.S. Treasury to ensure that nonpower functions of the federal dams bear their share of the costs of fish recovery. The power function should not bear the entire burden of those costs. These credits are lower for three reasons. First, they are linked to the price of power. When power prices decline, so, too, do the revenue credits. Second, between the time we established the CRAC mechanisms and the time when the rates went into effect, a reallocation of costs to the multiple project purposes of Grand Coulee Dam increased the power function's share and at the same time, lowered the level of credits available. Third, the FCCF was all but used up at the end of 2001 due to the severe drought and is largely no longer available.
- Lost hydro generation in 2002 due to the lingering effects of the drought in 2001 resulted in about $145 million in lost revenue. Additionally, in 2003 we expect revenue losses of about $200 million due to below-normal hydro conditions, and there will be smaller lingering effects into 2004.
- Credit exposure due to unpaid power bills by certain Northwest aluminum smelters and by the California Independent System Operator and Power Exchange is a new experience for the agency. We are currently owed more than $100 million by these insolvent or bankrupt enterprises.

## Impacts of droughts and the West Coast energy crisis

The experiences of the past few years have taught us several lessons to which we must respond through changes that will improve our performance.

A large portion of our financial problems can be traced to just two sources: two years of drought (out of the last three years) and the West Coast energy crisis. However, choices and assumptions made by Bonneville also contributed to the problems we face today. Many of these decisions were made in concert with BPA's customers and other regional stakeholders, but BPA was the final decision maker.

The impacts of the 2001 drought and the high wholesale power prices during 2000-2001 were profound. The unprecedented combination of factors resulted in BPA's power function losing in excess of $400 million. In addition, BPA used $245 million of revenue credits available from a contingency fund (the FCCF described above) used to cover fish-related costs in dry years, which all but depleted the fund and made it largely unavailable for future use. In 2002 there was a carry-over effect from the drought as reservoirs began the year less than full. All told, the drought and high prices created new direct costs of over $600 million just for basic operations to keep the lights on. The West Coast price escalation also led to more load being placed on BPA, which pushed BPA into an extremely high-priced market to acquire more power. This means that a significant fraction of the $4.3 billion in augmentation costs and increased IOU residential benefits, as shown in Figure 2 on page 15, would likely not have occurred but for this crisis.

The low 2002-2003 winter snow pack will also substantially reduce BPA revenues. Our current estimate is that revenues will be about $200 million lower in 2003 compared to our expectations. We expect 2004 will have smaller lingering revenue impacts due to 2003's below-average hydro conditions.

## What have we learned?

The lessons of this report, however, are not focused on the external events that have hampered our business operations. Instead, they are focused on actions that are within our control and that we can take to reduce our risk or improve our operations.

In many areas of our operation, we made good choices or took actions that helped reduce adverse impacts of the events that occurred. These include the adoption of the CRAC structure to accommodate the greater volatility and risk we now face; the development, in a very short time, of a reasonably priced portfolio of purchases to augment our firm resources; a load reduction program that kept dollars within the Northwest instead of sending them out of the region; and a successful debt optimization program that has reduced interest expenses and extended BPA's borrowing authority.

In other instances, however, there are some conclusions from the analysis that clearly identify choices we made that led to higher rates or contributed to BPA's current financial difficulties. We've learned several lessons from our experiences:

- Of the $5.3 billion of higher costs in 2002-2006 compared to the last rate period, about $3.9 billion is due to serving 3,300 aMW of load beyond BPA's resource base. BPA assumed substantial additional load service responsibilities, equivalent to more than all the total load growth in the region in the 1990s. Clearly, if BPA's costs and rates and risks are to be lower, then BPA's load-serving obligations will need to match up more closely with its resource base.
- Delays in defining our load-serving obligations led to increased costs and risks. We didn't sign Subscription contracts until less than one year before they went into effect, and that left us highly vulnerable to the very high market prices that existed at that time. We should have clarified our obligations sooner to avoid going into the 11th hour without adequate supply to meet demand.
- BPA receives substantial revenues from the sale of seasonal surplus power into secondary markets. While BPA's estimates of secondary revenues, made when we established the CRAC mechanisms in 2001, were lower than the then-prevailing market forecasts, they have proven to be too optimistic. Exacerbating the problem is that BPA made inflexible financial commitments based on the assumption that these secondary revenues would be realized.

- We need to better establish and manage our costs. Our costs for operating the system (BPA internal costs, Corps of Engineers and Bureau of Reclamation operation of the hydro system, and Energy Northwest operation of the Columbia Generating Station) exceeded the estimates that were developed by the Cost Review and adopted in the May 2000 rate case by a significant amount. This is the result of a number of factors:

  – The cost estimates were unrealistically optimistic, and the costs, once embedded in the rate case, were not backed by firm plans and agreements to manage to those levels.

  – Estimates of cutting by nearly half the internal operations costs were, in retrospect, not sustainable given (1) the increasing complexity of the task of managing the system and (2) the underlying business model that allowed the cost reductions assumed a reduced, simpler role for BPA (for example, limited amount of service to load, simple contracts, fixed rates) that ultimately was not adopted. While the rate case estimates do not appear to be achievable, BPA is seeking to maintain its internal operating costs at 2001 levels for the period 2003-2006, net of offsetting revenues.

  – Estimates of the cost of producing energy on the system (from the dams and the nuclear plant) were never committed to by the operators (Corps, Reclamation and Energy Northwest) and did not reflect the costs of properly maintaining an aging system.

  The lessons learned are that (1) costs and budgets should be realistic and established with a clear link to the outcomes desired, and cost estimates need to change if the fundamental assumptions underlying the estimates change; (2) we should obtain the support and commitment of our cost partners to our budgets; and (3) once budgets are established, we should develop firm plans and agreements to manage to those levels.

- The impacts of BPA's high rates have widely varied among BPA's customers. This creates issues of intraregional equity, and we need to take steps to minimize this in the future. There may be a need to allow for more flexibility in the structure of our contracts, or for shorter contract lengths, or for mechanisms that maintain equitable relationships between customer classes to allow for changing conditions that could significantly affect equity calculations and/or perceptions.

- BPA's culture is one that seeks to respond positively to a variety of service and funding requests while also seeking to avoid rate increases. This frequently results in BPA taking on substantial financial risks. We need to be rigorous, objective and realistic about the financial impacts of the obligations before we take them on.

- BPA has historically assumed and managed a significant amount of risk on behalf of its customers and others. However, BPA has gone beyond the limits of risk that it can take on in the face of these increases in risk and uncertainty.

- We believe there are a number of areas in which our management practices need to be improved.

  – We must have a clear view of the long-term outcomes that we seek to achieve and must establish measurable goals that support those outcomes. We dramatically switched directions during the 2000-2001 period from that of the Comprehensive Review, and that led to misaligned activities and inefficiencies. While we need to respond appropriately to changing circumstances, our response needs always to be in the context of a clear long-term vision and strategy that drives our actions. Establishing clear measures will enhance our understanding of our progress in achieving those desired outcomes.

- BPA's business systems and processes need to be enhanced. We need to better track actual costs against rate case assumptions and develop more responsive and standardized methods for modeling, testing alternatives and monitoring results. We must also ensure that we are effectively using BPA's enterprise software that relies on a common data architecture and data repository.
- We must ensure that we have strong analytic capabilities across many functions. We cut our load forecasting and rates functions to save costs in the late 1990s, and that reduced our ability to produce complete, timely and thoroughly coordinated analyses of the many complex rate and financial issues we encountered.
- We must improve our risk management practices. While BPA has always had to deal with a significant degree of uncertainty, the range of risks we now face has increased enormously. The sophistication of BPA's risk management has not kept up with the complexity of the restructuring market or the multiplicity of demands being placed on us by all our stakeholders. We must reconcile the difficulty involved with the relatively high certainty of our costs and the relatively low certainty of our revenues.
- We must enhance our executive and management skills and practices in several critical areas and improve aspects of our culture that will create a better flow of communication. Several points above relate to this area, including establishing and managing to clear outcomes and improving risk management practices. We need to improve communication up, down and across the agency to ensure that alternative views and ideas receive an appropriate degree of consideration.

## Next steps

This review of events, together with the lessons we have learned, is only valuable if it serves as a guide to future improvements. In some cases, we have already begun implementing some of the improvements that are needed; for example, the use of our enterprise software system to track and manage costs has been significantly improved over the last year. Our next step will be to develop a set of action plans that will guide our implementation of the additional improvements needed. A more detailed examination of some of the internal management and communication problems and recommended changes will be completed soon, as will a report documenting the changes we intend to implement in our risk management policies and practices.

All BPA's managers and employees take the stewardship role that has been entrusted to them very seriously. We know that our customers and the Northwest public expect improvements in the results for which we are responsible, and we intend to deliver on those expectations.

# What Led to the Current BPA Financial Crisis? A BPA Report to the Region

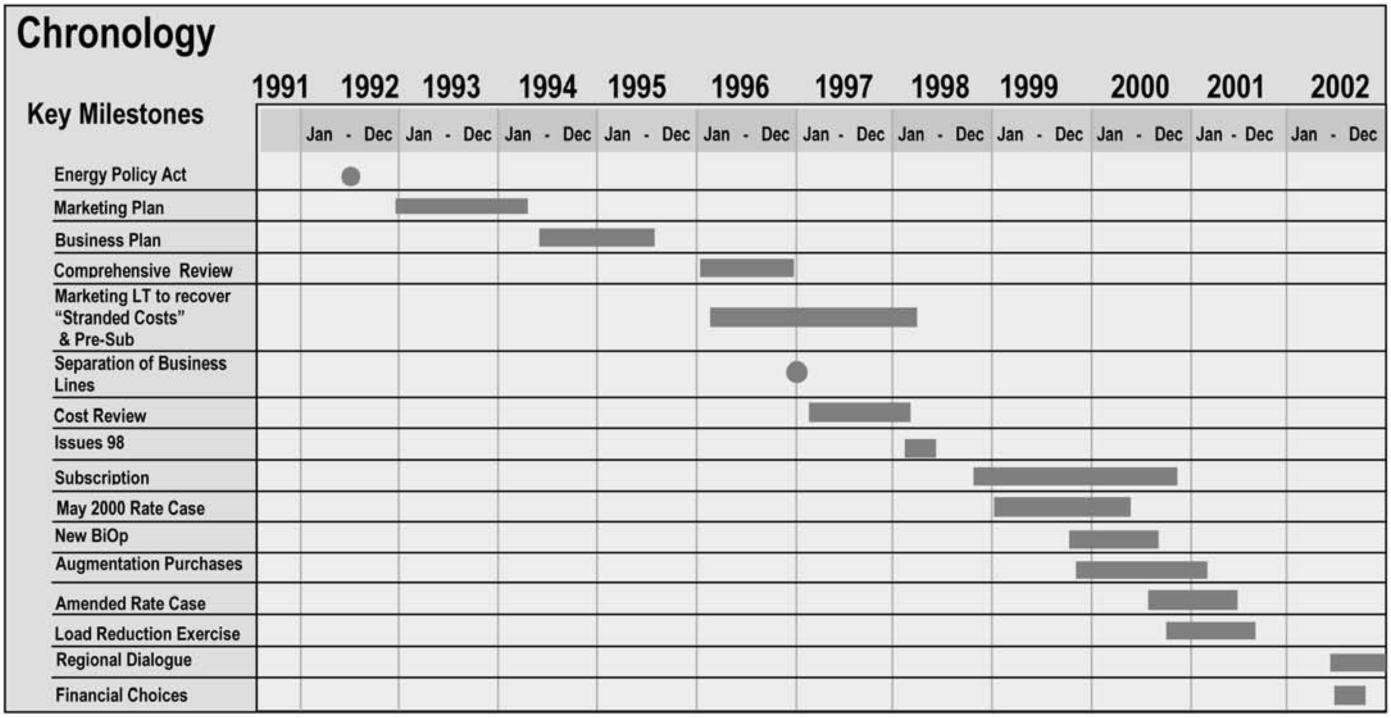
In May of 2000, the Bonneville Power Administration was on a path to sign long-term power sales contracts with an expectation that BPA wholesale power rates would not be significantly higher than they had been for the previous five years. From 1997 to 2001,[1] BPA's average preference power rates had remained steady at about $22 per megawatt-hour. During that time, the agency's financial reserves rose from $278 million at the end of 1996 to $625 million at the end of 2001. This was due largely to a period of very good hydro conditions. Under average water conditions, BPA would have expected to end the rate period with the same level of reserves that it had at the beginning. BPA's earnings from secondary (surplus) power sales helped keep rates steady and allowed reserves to increase. By May of 2000, end-of-year reserves were expected to be more than $850 million.

But our world began to change that May, and since then we have been on a much different path. BPA raised rates for 2002 an average of 43 percent over 2001 levels for most customers and, despite that, we've watched our reserves plummet toward zero, the lowest level in many years. As we go into 2004, we face the specter of another rate increase – possibly in the neighborhood of 15 percent above 2003 rates – to restore the agency's financial health.[2]

Given that this reality is a significant departure from our expectations just three years ago, we believe it is important to examine the chain of events that led to BPA's deteriorating financial condition and to see what lessons we can learn for the future.

[1] All years identified are fiscal years unless otherwise noted. BPA's fiscal year runs from October through September.

[2] All forecasts of revenue, expenses, market prices and hydro conditions are as of March 2003 unless otherwise noted.


Chronology
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Jan - Dec
Energy Policy Act
Marketing Plan
Business Plan
Comprehensive Review
Marketing LT to recover "Stranded Costs" & Pre-Sub
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Cost Review
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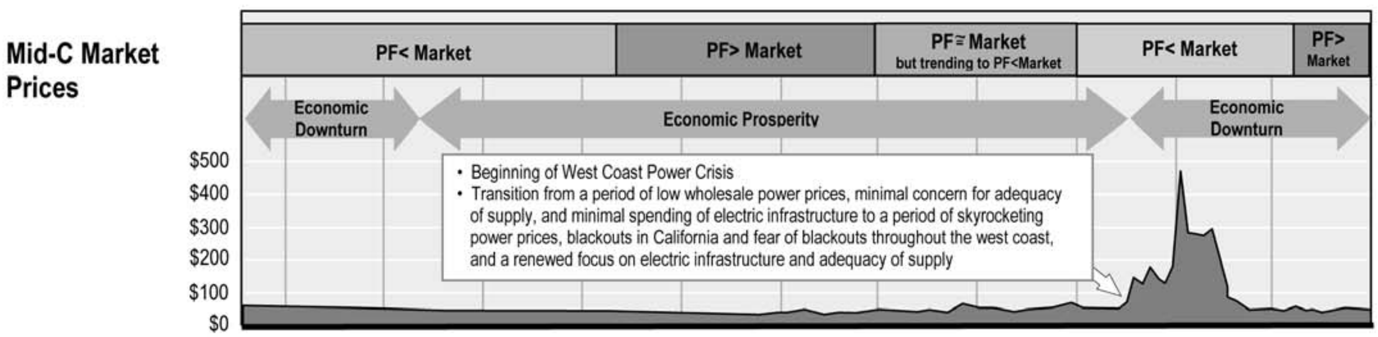
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Economic Downturn
• Beginning of West Coast Power Crisis
• Transition from a period of low wholesale power prices, minimal concern for adequacy of supply, and minimal spending of electric infrastructure to a period of skyrocketing power prices, blackouts in California and fear of blackouts throughout the west coast, and a renewed focus on electric infrastructure and adequacy of supply
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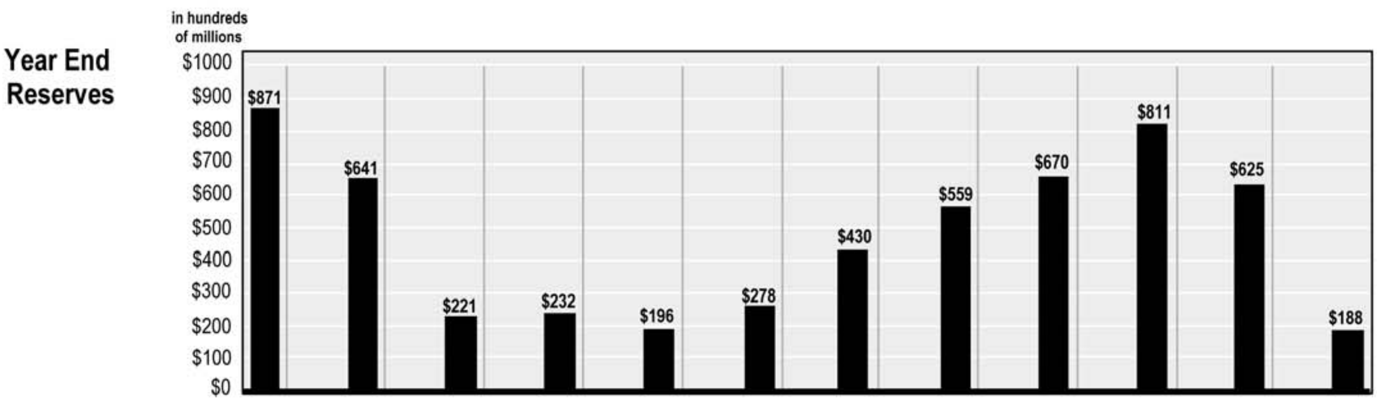
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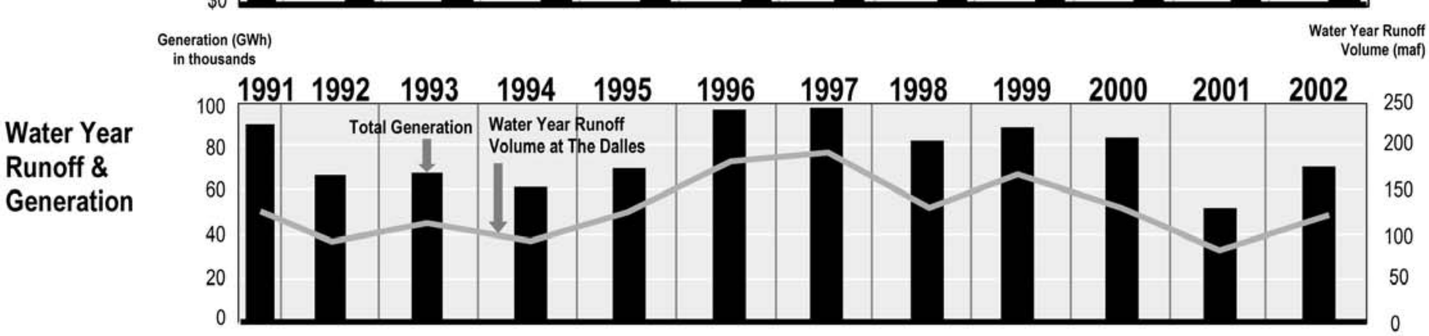
Generation (GWh) in thousands
Water Year Runoff Volume (maf)
Water Year Runoff & Generation
1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002
Total Generation
Water Year Runoff Volume at The Dalles
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60
40
20
0
250
200
150
100
50
0

# Background

## 1994-1996: Market prices fall below BPA's power rates

In 1994, market prices were dropping and conventional wisdom was that power market deregulation was likely to deliver consistently lower wholesale prices. By 1995, many BPA customers were clamoring to reduce their purchases from BPA so they could take advantage of lower prices offered by the burgeoning population of power marketers. The direct-service industries (DSIs) reduced their take from BPA by around 800 aMW in 1995, and public utilities followed in 1996 with over 1,000 aMW of load reductions. At this time, it was taken as a given by many of BPA's customers that they would no longer rely on BPA to meet all their requirements. The question was whether BPA could keep its costs low enough to avoid loss of so much load that a major "stranded cost" problem would result.

## 1996-1998: The Comprehensive Regional Review[3] and Regional Cost Review[4]

In 1998, a Regional Cost Review (Cost Review) of BPA was completed that set cost targets, many of which were incorporated into the May 2000 rate case and, as a result, were reflected in our base rates. The Cost Review was built on the earlier Comprehensive Regional Review (Comprehensive Review), which envisioned a dramatically shrinking role for BPA. Getting BPA's existing system power sold at cost was viewed as a major challenge in a persistent low-price wholesale power market. The goal was to drive costs down and get the entire Federal Base System committed under long-term power sales contracts. Our view was that keeping the price of the federal system competitive and covering costs required emphasizing cost minimization over output maximization in managing generating plants, cutting BPA power staffing by more than half by eliminating or nearly eliminating most functions except those required to operate the system, cutting the Northwest Power Planning Council costs by almost 20 percent, cutting conservation spending by almost 30 percent and cutting a variety of other functions.

BPA accepted the direction in the Comprehensive Review and adopted the overall cost reduction target recommended by the Cost Review. However, it should be noted that there was doubt within the agency that all the cost reductions could be achieved, and, furthermore, our cost partners within the Corps of Engineers, Bureau of Reclamation and Energy Northwest never committed to those cost targets. Nevertheless, considerable effort and planning took place from 1997 through 1999 within BPA to achieve the overall cost reductions defined in the Cost Review, though with a somewhat different mix of actions than specified in the Cost Review; we also assumed higher revenue levels than the Cost Review did. In retrospect, the forecast levels of expenses recommended by the Cost Review were unrealistically optimistic given the increasing complexity of the task of managing the power system and conducting essential functions.

## Pre-Subscription power sales contracts

Facing what was broadly believed to be a persistent struggle to sell power at prices high enough to cover costs, we sought out customers willing to make the kind of long-term

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3 Comprehensive Review Final Report, Toward a Competitive Electric Power Industry for the 21st Century, Document 96-CR26 (Northwest Power Planning Council).

4 Cost Review of the Federal Columbia River Power System Management Committee Recommendations, March 10, 1998, Document CR98-2 (Northwest Power Planning Council).

commitments to buy power at full cost envisioned in the Comprehensive Review. In 1997, we offered "pre-Subscription" power sales contracts to all our regional customers. Forty, mostly small full-requirements public utilities, took a perceived risk and signed these pre-Subscription power sales contracts offered by BPA at a guaranteed rate averaging about $22/MWh through 2006. BPA saw these sales as a means of providing some protection against stranded costs and demonstrating that BPA power could be competitive. These power sales contracts are now extremely beneficial for the utilities that signed them, but, at the time they were signed, many of these utilities were criticized for making such long-term high-priced purchase commitments. The pre-Subscription sales total about 950 aMW for the 2002-2006 period.

## May 2000: We thought we had wrapped up rates

In May of 2000, we thought we were wrapping up a two-year process of developing power sales contracts (known as "Subscription" contracts) and setting wholesale power rates for the 2002-2006 period. We completed and filed our rate proposal with the Federal Energy Regulatory Commission and were moving to sign Subscription contracts that included the 2002-2006 period based on those rates. The rates in the proposal to FERC in May 2000 averaged about $22/MWh for preference power – roughly the same as for the 1997-2001 period. Over the 2002-2006 period, we expected to earn a total of $414 million in net revenues.[5]

By the May 2000 rate proposal, we had departed from one of the key elements of the direction set in the Comprehensive Review. Market prices for wholesale power had slowly but steadily risen, creating a shift from a conventional wisdom that BPA would struggle to cover its costs and had to worry about "stranded costs," to steadily increasing customer interest in placing more and more load on BPA. Responding to what we saw as strong demands to do so, we departed from the Comprehensive Review mandate to limit power sales to the existing system. By October 2000, we had completed our Subscription process, signing new power sales contracts for a total load that exceeded the Federal Base System's capability by about 3,300 aMW.

Three major decisions led to greater sales. First, we did not tier our power rates or contractually limit public utilities' choices to buy from us up to their net requirements; many of BPA's public utility customers had argued strongly that tiering rates or taking other steps to limit sales to them was inappropriate. This decision made it feasible, even economically attractive, for many of our public customers to request load service up to their net requirements as they are allowed by statute. As of the May 2000 rate case, these loads were forecast to total about 5,200 aMW for the 2002-2006 period, though there was considerable uncertainty about this estimate as rising prices and a strong economy increased the retail loads of these utilities and increased their interest in buying more than that estimate. For context, the total public utility load placed on BPA in the 1997-2001 period was around 4,200 aMW.

Second, we agreed to sell up to 1,500 aMW to the direct-service industries in response to their fervent argument that to do otherwise would devastate many communities. The DSIs made this argument strongly and effectively – both in the Northwest and at the national level. At the time, we believed that we could accommodate them without significantly raising rates.

Third, some IOUs made vigorous arguments, through media campaigns and in other forums, that their residential ratepayers were not getting their fair share of federal system benefits. These arguments were strongly supported by state public utility commissions and bolstered by public

[5] In May 2000, we expected to earn a total of $414 million in net revenues after accounting for $121 million in risk allowance for non-operating cost uncertainty (see footnote 6).

campaigns. In response, we agreed to sell 1,000 aMW of power to investor-owned utilities for the benefit of their residential and small-farm consumers. We agreed to sell power to IOUs with the belief that the best long-term way to provide federal system benefits to these customers was to provide them power at the same price (and with the same risks) as our other customers. In addition to the 1,000 aMW of power sales to IOUs, we agreed to provide a cash payment designed to be the financial equivalent of another 900 aMW of power for the benefit of their residential and small-farm consumers. Again, we believed at the time, and told our public utility customers, that we could provide these benefits to IOU residential and small-farm consumers and additional service to the DSIs without increasing BPA power rates.

At that time, the following key expectations about the future were built into our rates. These assumptions were important in supporting our efforts to produce a rate proposal that offered no overall increase over the previous rates.

- **Additional load service & cost.** As a result of the three decisions described above, we predicted that the Subscription contracts would result in more than 1,700 average megawatts (aMW) of load beyond that which our generating assets could produce on a firm basis. We also expected we would be able to buy power at an average price of $28/MWh to serve that additional load. This assumption seemed reasonable given that, by May 2000, we had already purchased about 1,000 aMW for the 2002-2006 period at an average price below $28/MWh. We planned to cover most of the remaining need with a few hundred aMW of additional five-year purchases to be secured over the next year, leaving a small amount of the need to be covered in the short-term wholesale power market as necessary depending on actual hydro conditions.
- **Cost reductions.** We used a cost forecast that required that we come close to meeting the very aggressive cost reduction targets coming out of the 1998 Cost Review. We knew by then that our ability to achieve all the Cost Review cost savings was in doubt. For example, we had not followed through on the vision of BPA as limiting itself to selling just the existing federal system. We made some allowance for this through the addition of $121 million in expected costs through the risk analysis for non-operating costs.[6] Another example is that the Cost Review assumptions about Corps, Reclamation and Energy Northwest costs were extremely aggressive and were not supported by those partners.
- **IOU residential & small-farm benefits.** We expected to hold our cash payments to IOUs for their residential and small-farm consumers at about the same level as we paid from 1997 to 2001, which was about $70 million per year. In addition to this cash payment, we expected to sell 1,000 aMW of flat block power to IOUs for their residential and small-farm loads at about $20/MWh.

[6] Through the risk analysis for non-operating costs (called NORM), the May 2000 and June 2001 rate filing included an expected value of increased operating costs that was about $121 million more than the base case costs in the revenue requirement study. In essence, this risk analysis had the consequence of ensuring that rates were set high enough to cover the risk of certain expenses increasing. The risk analysis was done to recognize the difficulty of meeting those aggressive cost targets in light of the risks associated with the future that the Cost Review had assumed when making its recommendations. The NORM analysis used for these calculations can be found in WP-02-FS-BPA-03A, pages 19-20 or page 189. Not included in this evaluation are the possible increases in efficiencies modeled in the rate case.

- **Fish recovery.** We expected to increase our annual financial commitment to fish recovery (through cash outlays and operational costs) by about $80 million per year due to the change from the Fish Funding Memorandum of Agreement to the implementation of the 2000 Biological Opinion.
- **Fish credits.**[7] We forecast that we would receive nearly $600 million over the rate period in credits from the Fish Cost Contingency Fund and under section 4(h)(10)(C) of the Northwest Power Act.

### The world began to change

As we filed our rates, our world was changing. May 2000 was the beginning of the 2000-2001 West Coast energy crisis and marked the transition from a period of low wholesale power prices, minimal concern on the West Coast in general for adequacy of supply and minimal spending on electric infrastructure to a period of skyrocketing power prices, blackouts in California, fear of blackouts throughout the West Coast and a renewed focus on electric infrastructure and adequacy of supply.

As the West Coast crisis unfolded, it became ever more apparent that BPA's attractively low prices would cause customers to demand much more power than previously anticipated. Between May 2000 and November 2000, we finished signing Subscription contracts for 2002-2006, which gave us a clear picture of how much load we faced serving – about 1,600 aMW more load from public utilities than predicted in May 2000 and about 3,300 aMW more than our existing system could supply.

At the time, power to meet this load was increasingly scarce and it became apparent that the wholesale power market was far more volatile than we assumed in the rate case.

### Change leads to a supplemental rate case

Against the backdrop of the West Coast energy crisis, increased load placed on us and extremely high and volatile market prices, we asked the Federal Energy Regulatory Commission to stay the review of our rate filing while we conducted a supplemental rate case to reflect the new situation. At this point, we had a basic choice – we could either raise base rates substantially to recover the higher costs and much-greater risks, or we could leave base rates as proposed in May 2000 and institute a system of rate adjustment clauses that would raise rates only as necessary to cover actual costs and actual financial shortfalls. In close consultation with customers and other parties, we chose the latter.

We worked with customers to develop the three-layer system of cost recovery adjustment clauses (CRACs) with the objective that rates would be able to cover the cost of serving the additional load plus our other operating risks. The system of CRACs made it possible for us to avoid putting the risk associated with the severely volatile wholesale power market into our base rates. The load-based CRAC (LB CRAC) covered the direct cost of buying power and buying down loads (see below). The financial-based CRAC (FB CRAC) provided a fairly automatic, but limited, rate increase each year if our actual accumulated net revenues fell below certain

[7] These are credits toward our Treasury payments based on fish-related costs and impacts on operations. These credits contribute to BPA's overall revenue forecast through a Treasury payment credit that is based upon a calculation tied to market prices of power. When market prices are higher, the size of the credit available to BPA increases.

thresholds. We expected that the FB CRAC had a 25 percent chance of triggering each year. The safety net CRAC (SN CRAC), as the name implies, allowed the FB CRAC to be increased to cover extraordinary financial stresses. We expected there to be a very low likelihood that the SN CRAC would trigger.

In June 2001 we filed the final supplemental rate case with FERC that reflected these changes since May 2000.

### Covering the 3,300 aMW supply gap

The 3,300 aMW gap between our load obligations and the firm output of our existing federal system was very large – three times the consumption of the city of Seattle. As the full size of this obligation became clear, we accelerated efforts to buy power to cover the gap. We bought another 480 aMW for 2002-2006 after May 2000, but prices were rising relentlessly, mirroring a perception of a continuing shortage until new generation could be built – the same price rise that was causing our customers to maximize their reliance on our supply. By early 2001, it did not look possible to buy anywhere near 3,300 aMW of power at reasonable prices. We turned to our customers to ask for agreements to reduce their loads. The alternative we saw was purchasing power at astronomical prices that would have required approximately a 250 percent rate increase in October 2001, though that amount would have declined during the five-year rate period.

By June 2001, after a strenuous push by BPA, customers agreed to over 1,330 aMW of load reduction for the 2002-2006 period, for an average payment of roughly $30/MWh. By comparison, wholesale market prices for power for five-year purchases ran as high as $100/MWh in early 2001. Most public utilities and five of the six IOUs agreed to 10 percent load reductions in 2002, for an average payment of roughly $20/MWh. Some DSIs agreed to keep all their load off BPA for periods of up to two years for payments of about $20/MWh, with most of the payment required to go to pay salaries and benefits of out-of-work aluminum workers.

But by April 2001, we still had not met all the supply need and still faced the prospect of buying power for extremely high prices to cover the remainder of the need, which would cause our rates to more than double. We approached the IOUs about reducing our 1,000 aMW power delivery obligation to them. We offered two IOUs a payment of $38/MWh in 2002 through 2006 to eliminate their combined 620 aMW load on BPA. By comparison, market prices for 2002-2006 were at a level of nearly $100/MWh at the time. These companies were not willing to agree to this while they faced the threat of litigation taking their BPA benefits away. In response, we offered to pay them $38/MWh in 2002 and $45/MWh for 2003-2006 but with a discount back to $38/MWh if the litigation threat was settled by December 2001. Our view was that even the $45/MWh payment left our rates much lower in 2002 than the next-best alternative power supply to augment the Federal Base System, and this arrangement preserved the ability to bring the cost down to $38/MWh. Our view was that this arrangement was better than purchasing power from a marketer because the payments were required to flow to the residential customers of Northwest utilities.

An apples-to-apples comparison of these buydowns to the alternative purchases requires the lost revenue we would have received from the "bought down" load to be added to the buydown payment. Even with this addition, the buydowns were far lower-cost than the alternative purchases available at the time.

The action of augmenting the Federal Base System with firm resources to serve the additional load is known as "augmentation." To cover the costs of augmentation, rates for all but the pre-Subscription sales were set 46 percent higher than the May 2000 base case in the first half of 2002 through the LB CRAC. We structured our augmentation purchases so that they diminished over the five-year rate period, allowing us to take advantage of expected market price declines and thus bring the LB CRAC down. Because of this, we expected the LB CRAC to ramp down to the 25 to 30 percent range by 2004 as augmentation costs diminished.

### The June 2001 supplemental rate case

We did not conduct a full-blown rate analysis for the June 2001 filing. Instead, we left the basic revenue requirements analysis unchanged, thereby leaving BPA's base rates intact. However, we re-assessed the Treasury payment probability (TPP) analysis to reflect the major changes since May 2000. We built the following key expectations into the TPP analysis for the June 2001 rate filing:

- **Cost of additional load service.** We assumed that the LB CRAC would recover all the direct costs of augmentation above $28/MWh to serve the original 1,700 aMW plus all of the direct costs to serve the additional 1,600 aMW of load.
- **IOU residential and small-farm benefits.** We included an additional payment to the IOUs for their residential and small-farm consumers of $74 million per year above the original $70 million embedded in our base rates. This increase totals about $370 million over the 2002-2006 period. Our customers advocated for and we agreed to this additional payment because prices in the wholesale power market had increased greatly from the time we established the original payment in May 2000. This increase in payment is not connected to the payment we made to IOUs to reduce their load that is described above in "Covering the 3,300 aMW supply gap." With this increase, the annual cash payments to the IOUs for their residential and small-farm consumers totals about $144 million.
- **Secondary revenue.** We expected electric infrastructure development to take about two years to catch up with demand. As a result, we expected market prices for power to stay very high through 2003, making BPA's secondary sales revenue far higher than predicted in May 2000. For 2002, we predicted that revenues for our secondary sales would average $57/MWh versus $22/MWh on average that was assumed in the May 2000 rate case. Over the five-year period, we predicted that secondary net revenues would total about $1 billion higher than we forecast in May 2000.
- **Fish credits.** In June 2001, we forecast credits from the Fish Cost Contingency Fund and under section 4(h)(10)(C) of the Northwest Power Act to be about $150 million more in total over the five-year period than the May 2000 estimate, mainly because much higher market prices for power were predicted. With a forecast of higher wholesale market prices for power, 4(h)(10)(C) credits increased to cover higher costs to buy power to replace power lost to fish operations.

In the crisis year before June 2001, the world BPA faced appeared to be the opposite of what the Comprehensive Review envisioned. BPA's role was expanding in major ways – based on our understanding of increasing expectations from regional stakeholders – and priority went to expanding the amount of generating resources to serve an increasing load, rather than minimizing BPA's total costs, as concern grew about a multiyear period of inadequate generation infrastructure and high prices. In the face of the energy crisis and of the dramatic change in our future role relative to the world envisioned by the Comprehensive Review, we put more priority on dealing with these challenges than on managing cost to Cost Review levels.

By June 2001, it was clear that the forecasts of internal costs, hydro system costs and Energy Northwest costs in the May 2000 rate case were optimistic. In early 2001, we did not know the current magnitude of the cost increases over rate case estimates, described in Figure 2 on page 15, but we saw signs that there was pressure on the May 2000 rate case estimates of internal and generating system costs. It was becoming more likely that the forecast levels of expenses recommended by the Cost Review were not sustainable given the increasing complexity of the tasks of managing the power system and of conducting essential functions. Despite this, we decided not to modify the base rates for two reasons. First, rates needed to be in place by October 2001 concurrent with the new Subscription contracts, and there was no assurance a full rate proceeding could have been conducted within the time remaining. Revising the revenue requirement study would have lengthened the supplemental rate case process. Second, the Treasury payment probability analysis we performed suggested that revenues from secondary sales, even with very conservative assumptions relative to the actual forward market price for power existing at the time, would very likely cover any cost overruns.

### After June 2001: Recession and steep market price for power declines

Helped along by a struggling economy and the completion of several new power plants, wholesale electricity prices began to decline in the spring of 2001 and continued to drop more quickly and lower than virtually anyone expected. As late as April of 2001, forward wholesale electricity prices for 2002 had been well over $150/MWh. Actual spot electricity prices in 2002 averaged about $20/MWh for a flat block. Retail loads dropped for almost every utility. Electric-intensive industries and irrigated agriculture were (and are) being hammered by low commodity prices and high power prices. The Northwest aluminum industry, which had consumed over 3,000 aMW not long ago, was totally shut down because of low world aluminum prices.

### Differing impacts on Northwest interests

Now, in early 2003, the expectation that BPA's 46 percent rate increase in October 2001 would be significantly declining over the rate period is gone. BPA is struggling to minimize the size of a further increase. High retail rates, due to BPA wholesale power rate increases and power rate increases from a variety of other causes, are hurting a Northwest economy that has some of the highest unemployment rates in the nation. Additional industries could be forced to close by further power rate increases. Low-income ratepayers are having their service cut off for inability to pay and formerly irrigated land has returned to dry land farming.

The impacts of BPA rate increases have varied dramatically from customer to customer. Much of the money collected from higher rates is flowing back to other customers. The payments we made to the DSIs to reduce their load totaling $260 million in 2002 and 2003 have kept thousands of aluminum workers paid who would otherwise be out of work due to low aluminum prices. As a result of payments we made to reduce IOU load and a higher financial formula, the BPA payment to IOUs for the benefit of their residential and small-farm consumers has risen from about $70 million per year before 2002 to an average of over $400 million per year (an amount which includes load buydown payments of about $250 million per year), leaving residential rates for some IOUs largely unchanged. On the other hand, rates of surrounding public utilities have skyrocketed. The 40 customers who took the risk in committing to BPA power under pre-Subscription contracts when a $22/MWh rate looked high are now benefiting from those rates when other BPA customers are paying on average about $33/MWh.

## The impact of the West Coast energy crisis & the 2001 drought on BPA's finances

Prior to realizing that 2001 would bring a severe drought on top of the West Coast energy crisis already under way, we had expected to lose about $9 million in net revenue but we actually lost $418 million. For the 2002-2006 rate period, there were six primary impacts of the overlapping West Coast energy crisis and 2001 drought on BPA's current financial condition.

First, during this period we needed to secure much of the remaining firm resources to serve customer load placed on us through Subscription contracts. The severity of the drought highlighted the firm energy shortage in the Northwest and drove prices higher than we or the region at large had ever seen previously – and higher than we ever expected to see. The coincidence of the drought and the energy crisis during the time when we needed to purchase was the primary driver to our strategy to reduce load on BPA as the least-costly means to meet this load. Even so, the need to augment our firm resources during this period led to some substantial additional augmentation costs.

Second, we used $245 million of the Fish Cost Contingency Fund (FCCF) in 2001, using up about two-thirds of the total available. This contingency fund is maintained at the U.S. Treasury and can be accessed in low-water years. In effect, it has provided some insurance against droughts. Less than $80 million in total credits remain in the FCCF for use this year and in any other future year.

Third, because of the energy crisis in 2001, we are still owed a portion of monies by the California Independent System Operator and Power Exchange that we are seeking to recover through the California refund process. These funds are tied up in bankruptcy proceedings. As of today, the California Independent System Operator and Power Exchange still owe us roughly $90 million.

Fourth, in 2002 we experienced two lingering effects from the 2001 drought. Although the hydro condition appeared to be about normal over the January-July 2002 period, we had to store a significant amount of water to replenish low reservoirs from the 2001 drought, which caused hydro production in 2002 to be about 600 aMW less than average. Also, natural stream flows were well below average in the fall of 2001 (the beginning of our fiscal year). This resulted in an impact of approximately $145 million in lost revenue relative to our expectation in June 2001, shown in Figure 2 on page 15. Additionally, the power that was generated was largely during unexpectedly low priced periods during the summer of 2002.

Fifth, the 2003 water year is only about 70 percent of average,[8] and this drought is expected to cause lower revenues of about $200 million this year with smaller lingering revenue impacts in 2004.

Finally, the effects of the West Coast energy crisis and the 2001 drought are also manifested in an additional payment established in June 2001 to the IOUs for their residential and small-farm consumers over the 2002-2006 rate period because prices in the wholesale power market had increased so greatly from the time we established the original payment in May 2000.

[8] Forecast as of February 2003.

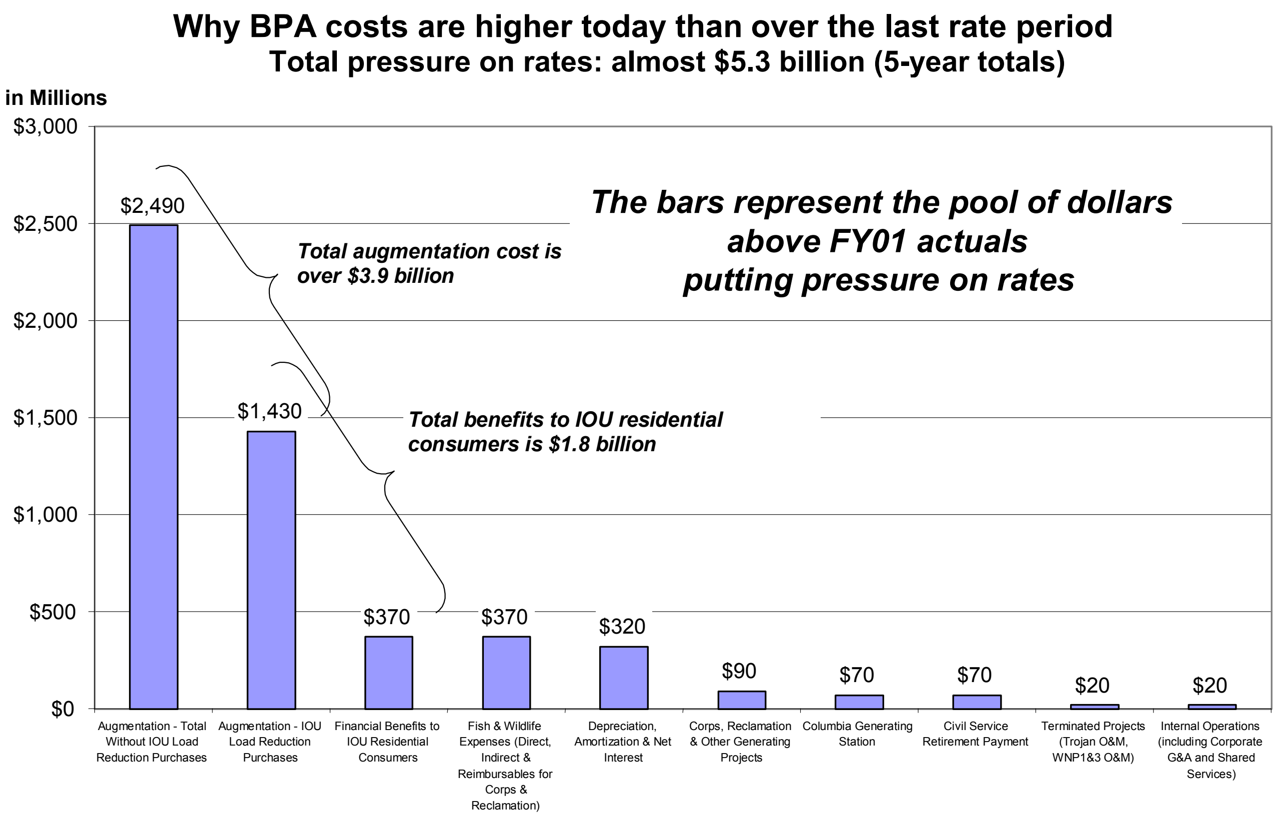
# Why BPA costs are higher today

### A comparison between BPA's costs in 2001 and today

The prior sections describe the chronology of development of BPA power rates over the last three years. This section addresses more specifically the factors that are causing costs to be higher than they were in the previous 1997-2001 rate period.

BPA's costs are over a billion dollars per year higher over the 2002-2006 period than they were in 2001. Following is a look at individual cost categories. The sources of the cost increase are shown in Figure 1 in order of magnitude and are described below. The chart lists five-year totals and is net of increased revenues that partially offset cost increases.

*Figure 1*




**Costs to augment the Federal Base System: $3.9 billion total increase, averaging $780 million per year.** BPA's customers were making decisions about how much federal power to buy from BPA just as market prices started to soar in the summer of 2000. By November 2000 when Subscription contracts were executed, the agency had contractual obligations to serve about 3,300 aMW of the region's load over and above what BPA's existing resources could supply. In order to meet our load obligation over the 2002-2006 period, along with wholesale market purchases of power and other actions, we agreed to pay IOUs to reduce their load with the stipulation that these payments would flow directly to their residential and small-farm consumers – these payments account for over one-third ($1.4 billion) of the $3.9 billion total increase. Augmentation costs increased rates 43 percent on average over base rates in 2002, for all but pre-Subscription customers. Since, over time, we expect augmentation costs will decline, we expect the percentage increase over base rates that recovers these costs (through the LB CRAC) will decline to roughly 31 percent on average for the 2004-2006 period.

Looking back, BPA's average direct costs of serving this additional load ($35/MWh) are reasonable in the context of today's marginal cost of new power plants but they are still much higher than the cost of the existing Federal Base System, which is dominated by low-cost hydro. Augmentation costs account for the largest cost increase, primarily because of the significant size of our obligation. The regional load was turning to BPA, but, had this load gone to other wholesale suppliers, regional ratepayers would have had rate impacts from those other sources as well. However, the distribution of those higher costs among various customer groups would likely have been different.

In 2001, there were no costs associated with augmenting the federal system. The term augmentation applies to those purchases we made to serve firm load under Subscription contracts that commenced in 2002. Therefore, the $3.9 billion increase over 2001 actuals represents the direct expenses associated with purchasing power to augment the federal system beginning in 2002.

**Financial benefits to IOU residential and small-farm consumers: $370 million total increase, averaging $74 million per year.** As described in the chronology on page 2, BPA made payments averaging about $70 million per year to IOUs from 1997 to 2001 to reduce the rates of their residential and small-farm consumers. We increased this amount to $144 million per year over 2002-2006, an increase of $74 million per year or $370 million in total over the 2002-2006 period. This increase was to reflect the higher market prices that were caused by the West Coast energy crisis. Including the payments described above to reduce the IOUs' load on BPA, benefits flowing to the residential and small-farm consumers now total over $400 million per year for the rate period as compared to about $70 million per year over the last rate period.

**Fish and wildlife costs: $370 million total increase, averaging $74 million per year.** Fish and wildlife costs are up about $74 million per year for the 2002-2006 period compared to the prior rate period. These costs include lost opportunity costs of operating the hydro system for fish mitigation, the operation and maintenance costs for fish and wildlife at U.S. Army Corps of Engineers and Bureau of Reclamation facilities, and expenses related to the Northwest Power Planning Council and Lower Snake River Compensation Plan hatcheries. The increase in expenses is due to the implementation of the 2000 Biological Opinion as compared to the Fish Funding Memorandum of Agreement in effect between 1997 and 2001. However, current fish and wildlife expenses are being managed within rate case forecasts.

**Debt service, depreciation and net interest expenses: $320 million total increase, averaging $64 million per year.** Net interest expense has substantially increased because of the reduction of interest income from having significantly lower cash reserves than we had in 2001. About $60 million of the increase is depreciation related to Conservation Augmentation, which we didn't have in 2001, from the projected fish-related appropriations of over $400 million that was to be declared in service during the 2002 to 2006 period and from additional investments in the hydro system.

**Federal hydropower and other generating projects costs: $90 million total increase, averaging $18 million per year.** The operating costs of the U.S. Army Corps of Engineers and the Bureau of Reclamation were relatively low in the late 1990s — to a point at which projected availability and future reliability of some of the hydro units began to suffer. Over the 2002-2006 period, these costs are somewhat higher compared to 2001, reflecting a so-far successful attempt to restore the condition of these assets. Included in these costs is a resource new to the FCRPS, Green Springs, operated by the Bureau of Reclamation and resources newly marketed by BPA for the National Park Service, Elwah/Glines. Security costs as a result of Sept. 11, 2001, have added $6.3 million annually (or $31.5 million in total over the rate period) to the current increase. Additionally, due to a cost reallocation of project purposes at Grand Coulee, a larger percentage of the project's costs are now allocated to power, thereby increasing costs above rate case projections. Other generating resources included in this category are resource output contracts for Cowlitz Falls, Wauna, Idaho Department of Water Resources Dworshak Project, Billing Credits generation and other projects.

**Columbia Generating Station costs: $70 million total increase, averaging $14 million per year.**[9] After significant cost cutting and deferred maintenance in the late 1990s, Columbia Generating Station expenses increased with capital investments to replace obsolete equipment, major maintenance activities to address projects deferred over the last three to five years, increased costs associated with on-site spent fuel storage and increased security to implement measures required by the Nuclear Regulatory Commission since Sept. 11, 2001. Security costs as a result of Sept. 11, 2001, have added about $4 million annually (or $20 million in total over the rate period) to the current increase.

**Pension costs: $70 million total increase, averaging $14 million per year.** These costs reflect the unfunded liability of the Civil Service Retirement and Disability Fund, the Employees Health Benefits Fund and the Employees Life Insurance Fund that was not covered prior to 1998. In general, these costs ensure that BPA employee pensions are covered through BPA's rates, not by the U.S. taxpayer. We delayed repaying these costs from the 1997-2001 rate period to the 2002-2006 rate period, which explains the dramatic increase relative to 2001 actuals.

**Trojan, WNP-1 and WNP-3 terminated projects costs: $20 million total increase, averaging $4 million per year.** Trojan nuclear plant decommissioning costs and other costs are up. For instance, slippage in the schedule of Trojan decommissioning has pushed actual costs into the current rate period from the last rate period.

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[9] This comparison was normalized to account for the two-year refueling cycle of CGS.

**BPA's internal costs supporting the power function: $20 million increase in 2002, $0 and no increases for 2003-2006 on average.**[10] Internal operating costs supporting BPA's power function[11] are those costs that sustain our many programs, including corporate overhead. We commit to managing our internal costs for 2003-2006 to 2001 actual levels, net of offsetting revenues.

## Why is BPA losing money?

### A comparison between forecasts when rates were set and today

The previous section described all the cost increases that are causing BPA's cost-based rates for 2002-2006 to be higher than they were in 2001. This section addresses a different question – why is BPA still expecting to lose money after all the rate increases that have already been put in place? (Note: This analysis doesn't include the cost of augmentation, since the LB CRAC is designed to recover revenues to cover all of those costs.)

The answer is two-fold: Some expenses have increased since the rate cases and revenue that BPA assumed it would receive when the CRAC mechanisms were established in June 2001 did not materialize. Increases in expenses are delineated in Figure 2 below by category.[12,13] On the revenue side, the most significant factor by far is the revenue from secondary sales that did not materialize in 2002 and is not expected to materialize over the remainder of the rate period due to lower prices we received and expect to receive for our secondary sales. Additionally, the impact of drought conditions has led to lower hydro generation in both 2002 and 2003. It is very difficult to predict hydro conditions and the market price for power, so estimates of the revenue impact of a dry year can vary widely. Areas that affect net revenues are depicted in Figure 2.

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[10] We are committed to manage the level of our internal costs for the 2003-2006 period on average to equal the 2001 actual level, net of offsetting revenues. The increase shown is solely due to the 2002 expense level being above the 2001 actual level.

[11] BPA's internal costs supporting the power function reflect all these factors: staffing and internal operating costs associated with Corporate and Shared Services; BPA's part of the joint management of the hydro system; Energy Northwest oversight; weather and stream-flow forecasting; system operations planning; schedule planning; pre-scheduling; duty scheduling; after-the-fact accounting of power transactions; administration of Canadian Treaty; rate setting; power billing; customer account executives and customer service support staff; development and administration of power sales contracts; resolution of major power-related public policy issues; public and internal communications; tribal relationship management; real-time, balance-of-month and forward bulk power sales; short- and long-term power purchasing; renewable resource development and green power marketing; development and management of conservation programs; various energy efficiency and conservation programs, load management and distributed resources programs; control center network development and maintenance; administrative information technology system maintenance; development and maintenance of automated systems for system management; PBL strategy development; PBL financial reporting, analysis and budgeting; risk management; and PBL human resources management.

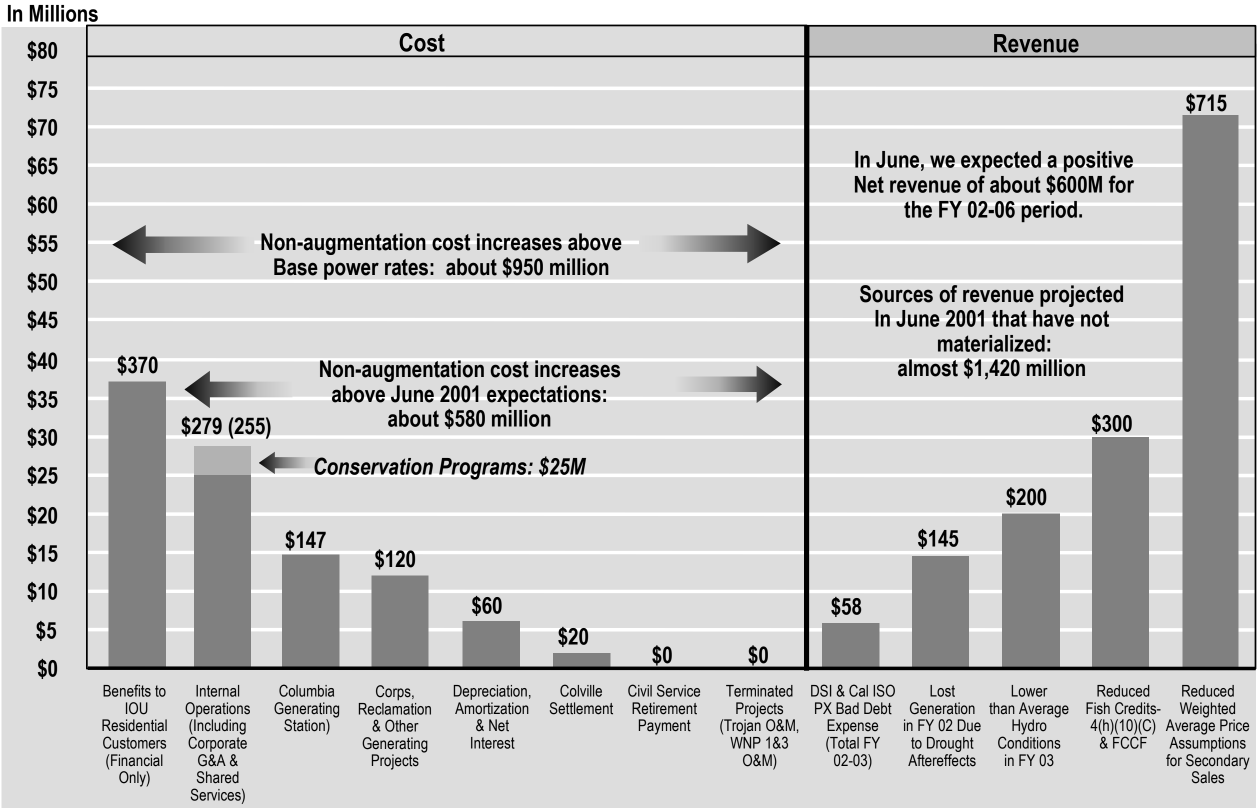
[12] Where applicable, the cost increases in Figure 2 are net of increased revenues that partially offset cost increases and are net of non-operating costs included in the risk analysis to address likely overruns in specific cost categories. (See footnote 6).

[13] Unlike Figure 1, augmentation expenses are not depicted in Figure 2. The direct costs of augmenting the Federal Base System are assumed to be fully recovered through the LBCRAC and therefore have perfectly offsetting revenues associated with them.

*Figure 2*

**Why is the PBL losing money?**

**Current projections compared to June 2001 expectation (5-year totals)**




**Financial benefits to IOU residential and small-farm consumers: $370 million higher than rate case in total, averaging $74 million per year.** BPA made payments averaging about $70 million per year to IOUs from 1997 to 2001 for their residential customers and small-farm consumers. In the May 2000 rate case, we embedded a similar amount of financial benefits to be covered by base rates. In June 2001, we included an additional payment to the IOUs for their residential and small-farm consumers of $74 million per year bringing the total financial payments to IOUs to $144 million per year. Our customers advocated and we agreed to this additional payment because prices in the wholesale power market had increased so greatly from the time we established the original payment in May 2000.[14] This increase in payment is not connected to the payments we made to IOUs to reduce their load, which are augmentation costs covered by LB CRAC and shown in Figure 1.

[14] See WP-02-E-BPA-74, page 8.

**BPA's internal costs supporting the power function: $279 million higher than rate case in total, averaging $56 million per year**.[15] Internal operating costs supporting BPA's power function are costs that sustain our many programs. In the rate case, the estimates for these expenses were largely based on the Comprehensive Review and the Cost Review recommendations described earlier.

Changes in this category are detailed in the next section titled "Cost Control Efforts." As previously noted, the Comprehensive Review and the Cost Review envisioned a dramatically shrinking role for BPA and a very simple wholesale power market and operating environment with less than half the FTE currently needed to operate BPA's power function. The implication of these reviews was that the fundamental relationship between BPA and its long-term power customers would significantly change and that BPA's traditional customer support services would no longer be needed. For instance, the Comprehensive Review assumed Northwest customers would not exercise their statutory right to obligate BPA to provide new resources and expanded services. Further, the Cost Review estimates were predicated on greatly simplified billing, scheduling and inventory systems. Similarly, the Cost Review contemplated Northwest Power Planning Council costs to be 20 percent lower than they are today.

Changes in the industry, however, have required significant personnel and information technology investments just to keep pace with the current complex wholesale power market and scheduling environment. While costs and staffing have been shrinking in many areas, such as account executives and their support staff, rates staff, market research, load forecasting, resource planning and development, and conservation, BPA's role has expanded in major ways. This has led to offsetting increases in costs and staffing in other areas, especially in the area of 24-hour seven-days-per-week scheduling information technology trading floor activities. In retrospect, we believe now that the forecast levels of expenses recommended by the Cost Review were unrealistically optimistic given the increasing complexity of the task of managing the power system and of conducting essential functions.

Also included in this category is $25 million of increased conservation expense. This reflects the increase in the conservation effort that began with the West Coast energy crisis over the 2000-2001 period.

**Columbia Generating Station costs: $147 million higher than rate case in total, averaging over $29 million per year.**[16] In the mid-1990s, Energy Northwest substantially reduced the cost of operating the Columbia Generating Station. We expected that the dramatic cost reductions experienced in the mid-1990s would continue through the 2002-2006 period. However, after significant cost cutting and deferred maintenance in the late 1990s, Columbia Generating Station needs increased capital investments to replace obsolete equipment, major maintenance activities to address projects deferred over the last three to five years, increased costs associated with on-site spent fuel storage and increased security to implement measures required by the Nuclear Regulatory Commission since Sept. 11, 2001. Security costs as a result of Sept. 11, 2001, have added about $4 million annually (or $20 million in total over the rate period) to the current increase. It should be noted that Energy Northwest had not committed to the rate case estimates for their costs during the 2002-2006 rate period.

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[15] The current expense level of our internal operating costs reflects our commitment to manage the level of our internal costs for the 2003-2006 period on average to equal the 2001 actual level.

[16] This comparison was normalized to account for the two-year refueling cycle of CGS.

**Federal hydropower costs and other generating projects: $120 million higher than rate case in total, averaging $24 million per year.** In the rate cases, the operating costs of the U.S. Army Corps of Engineers and the Bureau of Reclamation were predicted to be relatively low. What has materialized is that the expense projections were at such a low level that we believed availability and future reliability would have been jeopardized, based on subsequent benchmarking against other hydro plant operators. Further, rate case estimates did not have the benefit of system assessment benchmarking, which ensures that we are closely monitoring our investment levels vis-à-vis other comparable systems. Over the 2002-2006 period, these costs are significantly higher, reflecting a so-far successful attempt to restore the condition of these assets. Security costs totaling $6.3 million annually (or $31.5 million in total over the rate period) as a result of Sept. 11, 2001, have added to the current increase and were, of course, not contemplated in the rate cases. Additionally, due to a cost reallocation of project purposes at Grand Coulee, a larger percentage of the project's costs are now allocated to power, thereby increasing costs above rate case projections. Reimbursable fish and wildlife program costs covered by the Corps and Reclamation are embedded in the estimates above. Also, included in this category are other resource output contracts for Elwah/Glines, Greensprings, Cowlitz Falls, Wauna, Billing Credits generation and other projects. Compared to the rate case, these projects have increased costs of almost $3 million annually or $14 million in total over the rate period.

**Debt service, net interest and depreciation: $60 million higher than rate case in total, averaging $12 million per year.** Net interest expense has increased primarily because of the reduction of interest income from having significantly fewer cash reserves than we expected in the May 2000 rate case. The other factor is in federal projects depreciation, specifically conservation. We did not have Conservation Augmentation capital in the rate case and coupled with the policy for writing it down only over the period through 2011 (versus the standard 20 years for Legacy conservation), depreciation has increased.

**Colville settlement: $20 million higher than rate case in total, averaging $4 million per year.** The Colville Settlement is the program for settling with the Colville Nation lands lost with the construction of Grand Coulee dam and is based on an algorithm of actual generation from Grand Coulee with sales revenue. Until recently, the average annual payment has been about $16 million, but market prices in 2001 caused it to increase to over $21 million for 2002. To the extent that the price we receive for our secondary energy is higher than what we originally expected in May 2000, the cost of the Colville settlement will increase, since the payments are a direct function of the revenue produced by the dam. Additionally, increased efficiency (generation) at Grand Coulee is expected to drive the costs of the settlement higher than historic levels, thus increasing the expenses over rate case levels.

**Pension and terminated project costs** are not up relative to the rate case.

**Cal ISO/PX & DSI bad debt expense: $55 million total (2002-2003).** BPA is owed a total of over $120 million from California parties and the DSIs, and about $55 million has been written off since the start of FY 2002.

*California receivables*: The California Independent System Operator (ISO) and California Power Exchange (PX) owe BPA a total gross amount of $90 million. BPA has established a bad-debt reserve of $39.4 million related to these California receivables. ($24 million was booked in

2002 and $15.4 million in 2001). Significant events, including FERC refund hearings and bankruptcy hearing for PG&E (Pacific Gas & Electric) and the PX, need to be concluded before BPA can determine how much of the receivable will be collected.

*Direct-service industry receivables:* There are three primary DSIs that have significant overdue receivables to BPA. Two of these entities have filed Chapter 11 bankruptcies. In total, these DSIs owe BPA a total gross amount of $34 million. BPA established a bad-debt reserve of $31 million (in 2002) related to these DSI receivables. The DSI receivables are related to liquidated damages, transmission services provided and power that has been delivered. Claims for future damages will be determined by the bankruptcy court proceedings.

**Impact of drought conditions.**[17] The 2002-2006 period has gotten off to a very bad start in terms of hydro production, and our current five-year financial forecasts reflect this. The lingering effects of the 2001 drought on the 2002 hydro conditions and the poor hydro conditions in 2003 are costing BPA almost $350 million. Two drought years so close together is a huge hit to BPA's revenue picture and adds to the upward pressure on rates. When we set rates, we base our projections of net secondary revenue on the average historical runoff on the Columbia River system. Net secondary revenue is a function of hydropower inventory (stream flows) and the price we can get for that inventory.

**Lost revenue from reduced hydro generation in 2002: $145 million total (2002).** In 2002 we experienced a lingering effect from the 2001 drought. Although the hydro condition appeared to be about normal over the January–July 2002 period, we had to store a significant amount of water to replenish low reservoirs from the 2001 drought, which caused hydro production in 2002 to be about 600 aMW less than we expected. Also, natural stream flows were well below average in the fall of 2001 (the beginning of our fiscal year) and the power that was generated was largely during low-value periods during the summer of 2002. This resulted in an impact of approximately $145 million in lost revenue relative to our expectation in June 2001.

**Lost revenue from reduced hydro generation in 2003: $200 million.** This year, again, we are experiencing below normal hydro conditions. As of March 2003, we are now looking at a hydro volume forecast that is 70 percent of normal which we expect to result in about 20 percent less hydro production or about 1,200 aMW less secondary energy to sell. We expect this impact to result in about $200 million in lost revenue relative to our expectation in June 2001. Although it is not illustrated in Figure 2, we also expect that drought conditions this year will, in turn, result in a less than average hydro condition in 2004, which will produce smaller lingering revenue impacts in 2004.

**Reduced 4(h)(10)(C) and FCCF credits: $300 million total.** Over the 2002-2006 rate period, the credits toward our Treasury payments based on fish-related costs and impacts on operations are expected to be over $300 million less in total than we assumed in June 2001 for several reasons: a reallocation of project purposes at Grand Coulee, a lower forecast of power market prices and reduced availability of Fish Cost Contingency Fund credits that were all but exhausted at the end of 2001 because of the severe drought.

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[17] These Figure 2 bars attempt to isolate the impact of reduced generation due to drought effects. These bars do not reflect price changes relative to June 2001 expectations, which are shown in a subsequent bar.

**Lower secondary revenues due to lower price received for surplus sales: $715 million total.**[18] Net secondary revenue from our surplus power sales is far and away the key variable in determining our financial fate. These revenues often provide 20 to 25 percent of BPA's total revenues in a single year, so they help keep firm power rates down. As previously noted, in June 2001, we expected that electric infrastructure development to take about two years to catch up with demand. As a result, we expected market prices for power to stay relatively high through 2003, allowing BPA to earn significant secondary sales revenue under normal hydro conditions. For 2002, we predicted that revenues from our secondary sales would average $57/MWh. In 2002, market prices for power plummeted, and the actual price we received for our secondary energy turned out to be about $22/MWh – $35/MWh <u>lower</u> than our forecast in June 2001. Under normal hydro conditions, it now appears that the price we receive for secondary energy in the future will not reach our June 2001 forecast levels through the rate period.

**Other revenue impacts not depicted in Figure 2.** There are several other changes that have occurred since the May 2000 rate case that affect revenue. Although we have not precisely quantified these changes, it appears that they roughly offset each other.

- **We sold a flatter load shape than we assumed in base rates.** The May 2000 rate case assumed no sales of the Slice[19] product when, in fact, after Subscription contracts were all signed by November 2000, many customers had purchased a combination of Slice and block power. The "flatter" load shape of the block purchases reduced the average price paid for non-Slice requirements power. Additionally, in general, loads are not as high during peak periods as we expected in May 2000. For instance, mild weather in 2002 and 2003 made the load shape flatter than was expected which resulted in lower revenues from demand charges. Offsetting this somewhat is the fact that more secondary energy has been available in peak periods, which has likely increased the average price of secondary sales to some degree. However, it is difficult to isolate this impact and therefore quantify with any precision because of the variety of factors noted below.
- **Revenue from secondary sales is different today than we assumed in May 2000.** A variety of factors complicate the comparison of rate case estimates to actuals and current forecasts of revenue from secondary sales. One conclusion that can be made is that we expect to receive a slightly higher price on average for the 2004-2006 period for our secondary sales than we assumed in May 2000 – between $2-$3/MWh under normal water conditions. A dissection of our revenue from secondary sales is complicated by the following differences between our expectations in May 2000 and today. Actual hydro generation in 2002 and 2003 was very different and lower than what was modeled in May 2000; there have been many changes to our hydro regulation studies since May 2000 that are difficult to isolate; both the actual and current forecast load of our requirements customers is different; overall firm load

[18] This bar attempts to isolate the impact of our expectation that we will receive lower prices for our secondary sales as compared to our expectation in June 2001 under average water conditions. This bar does not factor in the reduced generation experienced in 2002 and 2003, which are reflected in previous bars.
[19] "Slice" is a new power product that BPA starting selling in FY 2002. Customers buying Slice pay an agreed-upon percentage of BPA's actual power costs and in return they get the same percentage of the actual output of the federal system, on an hour-by-hour basis. This greatly changes the shape of deliveries to these customers, compared to traditional power products.

levels (actual and forecast) are different; and, we secured augmentation based on a forecast load shape which is proving to be different than our actual firm load, making some firm resources available at times to be sold with our secondary sales. All of these factors are occurring simultaneously, which make it very difficult to isolate causal factors.

- **We entered into load reduction agreements with IOUs, public utilities, DSIs and other parties who had firm contracts, which appear to have an unintended impact on our revenue.** While the costs of serving the additional load placed on BPA is covered by the LB CRAC revenue and is, therefore, not depicted as an expense increase, the massive load reductions done to meet greatly increased augmentation needs were not anticipated in the rates process. It appears that these load reductions had at least two effects on our overall revenue picture, but they are very difficult to track precisely. First, as part of reducing load, we terminated or bought out contracts that were bringing in more revenue per MWh (which served as a credit to our revenue requirement in our base rates) than the load that the freed-up resource was to serve. In other words, we are receiving less revenue for that reduced megawatt-hour than we needed to recover in our revenue requirement. Second, we reduced a significant amount of load in the early part of the rate period ─ to the point that we reduced load that was covering part of our base revenue requirement. That is, we reduced not only the additional 1,600 aMW of load placed on us after establishing the base rate in May 2000 but also some of the load that we expected to serve as a part of our base rates. Because we reduced the load – and in some cases there was not a corresponding freed-up resource – the impact is that a portion of our base revenue requirement is not being recovered as we expected.

All of these changes have interrelated effects that are very difficult to separate and quantify. However, based on some rough comparisons, it appears that, in aggregate, these revenue changes roughly balance out to have no net effect on revenues and, thus, do not contribute to explaining the net revenue reduction from the May 2000 rate case. More precise estimates of these effects would require a great deal more effort.

## Cost control efforts

As shown in Figure 2, costs that are much above rate case forecasts are a major driver of BPA’s current financial crisis. As presented above, major categories that are higher than rate case estimates are operations and maintenance costs for the hydro system, operations and maintenance costs for the CGS nuclear plant, depreciation/amortization/net interest and BPA internal operating costs recovered in power rates. Compared to actual costs prior to this rate period, these costs have not grown dramatically, or at all in the case of internal costs, but the forecasts built into the rate case called for decreases in these costs.

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. We have consulted with our customers and others through the Financial Choices process in 2002. So far we have identified $350 million in expense savings, expense deferrals and other actions (about $292 million is directly attributable to closing the gap between revenues and expenses). 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 BPA's internal operating costs. These costs were forecast to increase from actual 2001 levels. So far, we have brought 2003-2006 costs back down to 2001 actual levels, accounting for offsetting revenues, with no allowance for inflation. To do this, we are bringing many cost categories down below 2001 actual levels. Categories that are being cut to below 2001 actuals include:

- **Travel expenses** – Cut approximately in half from 2001 actuals (will save over $1.5 million over four years compared to 2001 actuals);
- **Training expenses** – Cut approximately by two-thirds from 2001 actuals (will save almost $1 million over four years compared to 2001 actuals);
- **Monetary awards** – Cut approximately 95 percent from 2001 actuals (will save over $7 million over four years compared to 2001 actuals);
- **Retention allowances for critical employees** – Eliminated (will save over $3.5 million over four years compared to 2001 actuals);
- **Materials and equipment expenses** – Cut significantly from 2001 actuals (will save over $25 million over four years compared to 2001 actuals);
- **Research and development spending** – Significant cut from 2001 actuals and fuel cell program terminated ($26.6 million reduction in Energy Efficiency and Conservation programs, including Market Development, Technology Leadership/Energy Web, Legacy Conservation contracts and Market Transformation);
- **Market research analysis** – Significant cut from 2001 actuals;
- **Association memberships** – Most canceled;
- **Rate staff, load forecasting staff and power account executives** – Reduced by over 25 percent over last five years to about 70 employees;
- **Communications and community outreach programs** – Reduced significantly from 2001 actuals; and
- **Nuclear oversight staff** – Cut in half due to improved performance of the Columbia Generating Station plant in the 1990s – reduced to seven employees.

We have placed a moratorium on outside hires with limited exceptions and have offered early retirement to reduce employment levels. We have canceled or deferred major information technology development projects such as the new Generation Management System, Real Time Operations Dispatch and Scheduling System (RODS) Migration project and System Backup and Recovery project. 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 separately for it.

Despite these decreases, we have not yet brought total internal costs down below 2001 because there have been offsetting increases (or lack of decreases) in other areas. Some of these increases have been driven by the fact that BPA's power business volume increased greatly by the 3,300 aMW of additional load added in Subscription, which in turn increased the number and diversity of contracts to administer, added dozens of power purchase agreements and greatly increased the effort required to manage an extremely complex rate structure. The split of power and transmission business lines and compliance with FERC standards of conduct and other requirements has increased costs and staff demands. The increasing risks and revenue opportunities in the power market have dictated increases in staff to manage those risks and maximize surplus revenues, and increases in spending on automated systems to manage business and operational functions. Conservation and renewable resource development has remained a focus. A constant flow of regional policy issues has required ongoing staffing, as has RTO development and administration of the Asset Management Strategy with the Corps and Reclamation. Increases include:

- The number of duty schedulers, prescheduling staff, after-the-fact accounting staff and real-time trading staff on each shift to handle FERC mandates; the need to schedule transmission separately; Slice scheduling handling a greater volume of transactions due to Subscription power sales contracts and augmentation contracts.
- The workload associated with implementing the three CRACs.
- Hydro operations planning staff, to manage fish operations requirements and improve system optimization.
- Generation oversight staff, to develop and manage the hydro system Asset Management Strategy with the U.S. Army Corps of Engineers and the Bureau of Reclamation.
- Information technology systems development and maintenance staffing and contract costs, for the development of enhanced systems to meet FERC requirements and to optimize system operation.
- Transmission acquisition and management staffing and systems, to comply with FERC standards of conduct.
- Regional transmission organization development staffing.
- Risk management staffing.
- Legal staffing.
- Communications staffing.

Additionally, BPA is seeking greater efficiencies (while still complying with Standards of Conduct) in a number of functions that were dispersed across the organization when separate Transmission and Power Business Lines were created. The functions being addressed in this effort include:

- Power and Transmission billing.
- Financial reporting and analysis.
- Public affairs and public communications.
- Procurement.

- Training.
- Scheduling.
- Security.
- Information Technology.

In retrospect, the goal of cutting BPA's internal operating costs that support the power function roughly in half – as proposed in the Cost Review and largely reflected in the rate case – was overwhelmed by the large increase in business volume in Subscription and by the other changes in the industry which affected BPA's workload.

Our generation partners – Energy Northwest, U.S. Army Corps of Engineers and the Bureau of Reclamation – have all provided substantial cost reductions and deferrals from their planned budgets as well. Nonetheless, 2002-2006 operations and maintenance costs for the hydro system and nuclear plant are higher than those used in the rate case, and, to a lesser extent, they are higher than 2001 actuals. All three organizations are committed to seek further prudent cost reductions.

Extensive national and international benchmarking studies for the hydro system indicate that its operations and maintenance costs are about in the middle of comparable systems, suggesting that large additional operations and maintenance cost reductions for the hydro system are not likely achievable without degrading reliability and output.

Efforts to benchmark the operations and maintenance costs of the CGS nuclear plant are continuing. This study may or may not conclude that significant further reductions at CGS are possible while maintaining safety and reliability. In any event, post-September 11th security costs will continue to run higher into the foreseeable future.

In part, operations and maintenance costs of the generating system are higher than expected in the rate case because BPA and these agencies put priority on reliability and output maximization during the 2000-2001 period. But similar to BPA's internal operating costs, the conclusion in retrospect is that although these agencies will strive to bring costs down, the operations and maintenance costs for the generating system included in the rate case are not achievable, given the importance of maintaining an aging system for the future.

## What have we learned?

The analysis section above has provided a detailed examination of the chronology of events leading to the rate and financial crisis that BPA faces and of the specific factors that have created this situation. This section addresses some conclusions and the lessons we believe we need to learn from this examination of history, in the interest of avoiding a repetition.

### Significant drivers: Drought and the West Coast power crisis

The impact of the two years of drought (out of the last three years) and the West Coast energy crisis has been very significant. The 2001 drought and high wholesale power prices resulted in BPA losing in excess of $200 million that year. In addition, BPA used up $245 million of "fish credits" available from a contingency fund used to cover costs in dry years, leaving very little in this key 'insurance fund.' In 2002 there was a carry-over effect from the drought as reservoirs began the year less than full. All told, the 2001 drought and high prices created direct costs of approximately $600 million just for operations to keep the lights on. The West Coast price escalation during the power crisis had the compounding effect of increasing the load being placed on BPA, while simultaneously greatly inflating the cost of serving that load. This means that a significant fraction of the $4.3 billion in augmentation costs and increased IOU residential benefits shown in Figure 2 above would not have occurred without this crisis period.

The 2003 drought will also substantially reduce BPA revenues. Our current estimate is that revenues will be about $200 million lower in 2003 compared to what we expected just a year ago. We also expect that the below-average hydro conditions this year will reduce secondary revenues next year due to a lingering drought effect of lower than average generation for 2004.

But while drought and the market crisis dealt us a difficult hand, the key question for this report is what we can learn from these events to improve our performance on behalf of the region in the future. Following are what we believe are the most important lessons we learned.

## Some things went well

Most of the lessons learned below are about things that we need to do better or at least differently in future. First, we should recognize the things that turned out well and that we may want to build on or repeat.

- **CRAC structure:** In retrospect, collaborating with customers to put the CRAC mechanisms in our power rates was an appropriate response to risk. Having to use those mechanisms to the extreme extent that we are now is causing us and our customers great distress, but having a fixed rate structure without these CRACs could have left BPA with a much more dire financial outlook than even the one we now face.
- **Augmentation portfolio:** We started early (in 1999) purchasing power to meet 2002-2006 firm power needs. Overall, the portfolio of power purchases and load reduction has a reasonable price – about $35/MWh – even after averaging in high priced purchases from Enron and other parties.
- **Load reductions keep dollars in the Northwest:** Load reductions are a very large part of our augmentation portfolio and cost structure and, therefore, are a large part of our rate increase. One positive result of relying on load reductions in the augmentation portfolio is that total costs are lower than they would have been if augmentation had relied entirely on power purchases. Another benefit of the load reduction approach is that a significant fraction of the dollars collected through higher rates is going back to Northwest citizens through higher payments to IOUs for their residential ratepayers and full-salary payments to aluminum workers who would otherwise be out of work. This is of little consolation to utilities whose rates are far higher than they expected, but Northwest average retail rates and unemployment rates are lower than they would be if the same dollars had flowed to power marketers for purchases.
- **Conservation jump started:** BPA accelerated the implementation for its two major rate case conservation programs eight months early to assist with the Energy Crisis. The Conservation and Renewables Discount (C&RD) and the Conservation as part of Augmentation (ConAug) programs provided opportunities for customers to re-engage in conservation. Many customers used these programs as part of their load reduction portfolios.

This enhanced the re-establishment of a robust conservation delivery infrastructure that is paying dividends for the region now and into the future.

- **Debt optimization:** The debt optimization program, if followed to its fullest extent, can save ratepayers about $20 million per year while freeing up borrowing authority to be used for needed infrastructure projects.

### Lesson learned: Our costs and risks are driven heavily by the load obligations we assume

This perhaps is an obvious lesson, but in 1999 and 2000, before the large run-up in market prices, we believed we could acquire power to meet demands at a low-enough price to avoid significant rate increases, based on our experience in buying the first 1,000 aMW. Now, of the $5.3 billion of higher costs from 2002-2006, about $3.9 billion are due to serving 3,300 aMW of load beyond BPA's resource base. BPA took on substantial load service responsibilities, equivalent to more than all the total load growth in the region in the 1990s. Clearly, if BPA's costs and rates are to be lower, then BPA's load obligation will need to match up more closely with its resource base. Alternatively, if we take on more loads than our existing system can serve, we need to be very careful to assess the costs and risks of doing so. The decision needs to be well-connected to our long-term objectives and financial structure, and we need to be as clear as possible in explaining these effects to our customers and others affected by those decisions.

### Lesson learned: Delay in defining and meeting load obligations increased cost and risk

Again, this lesson may appear obvious in retrospect, but we believe it is key for the future. Subscription contracts were not all signed until less than a year before the new contracts went into effect, and market prices at the time were skyrocketing due to the West Coast energy crisis of 2000-2001. We could have avoided this situation by clarifying our load obligations and buying power sooner, or by limiting our load obligations through tiering rates or contractually limiting purchases. Either way, the lesson for the future is that we need to avoid again finding ourselves at the 11th hour without adequate supply to meet demand. The ongoing Regional Dialogue process will be key to achieving this early clarity.

### Lesson learned: Relied too much on highly variable secondary revenues to cover largely fixed costs

One very clear lesson is that we need to change how we treat secondary revenue forecasts in rate setting. In our June 2001 rate analysis, we forecast 2002-2006 secondary revenues over a billion dollars higher than we had predicted just a year ago. While BPA's estimates of secondary revenues made when rates were established in 2001 were consistent with then-prevailing market forecasts and the rates analysis did address the uncertainty of these revenues, they have proven to be too optimistic and we effectively relied on this variable revenue source to cover costs that were largely fixed. A major lesson learned is that we need to take a different approach to the high variability of secondary revenues in future rate setting. There are a variety of ways to do this, but change in this area is essential.

### Lesson learned: Need to better establish and manage costs

We need to better establish and manage our costs. Our costs for operating the system (BPA internal costs, Corps of Engineers and Bureau of Reclamation operation of the hydro system and Energy Northwest operation of the Columbia Generating Station) exceed the estimates that were developed by the Cost Review and adopted in the May 2000 rate case by a significant amount. This is the result of a number of factors:

- The cost estimates were unrealistically optimistic and the costs, once embedded in the rate case, were not backed by firm plans and agreements to manage to those levels.
- Estimates of cutting by nearly half the internal operations costs were, in retrospect, not sustainable given (1) the increasing complexity of the task of managing the system and (2) the underlying business model that allowed the cost reductions assumed a reduced, simpler role for BPA (for example, limited amount of service to load, simple contracts, fixed rates) that ultimately was not adopted. While the rate case estimates do not appear to be achievable, BPA is seeking to maintain its internal operating costs at 2001 levels for the period 2003-2006, net of offsetting revenues.
- Estimates of the cost of producing energy on the system (from the dams and the nuclear plant) were never committed to by the operators (Corps, Reclamation and Energy Northwest) and did not reflect the costs of properly maintaining an aging system.

The lessons learned are that (1) costs and budgets should be realistic and established with a clear link to the outcomes desired; cost estimates need to change if the fundamental assumptions underlying the estimates change; (2) we should obtain the support and commitment of our cost partners to our budgets; and (3) once budgets are established, we should develop firm plans and agreements to manage to those levels.

### Lesson learned: Long-term contracts that can lead to inequitable results need to be avoided

Some customers have been largely protected from the negative consequences of BPA's financial difficulties. Utilities that signed pre-Subscription contracts will be paying lower rates of roughly $22/MWh through the entire five-year rate period, as they are not subject to the CRACs. Investor-owned utilities have contracts that provide them with fixed benefit payments for the entire five-year period. These contracts were offered, negotiated and signed in the context of the conditions that existed at the time; BPA often needs to make business decisions that have long-term risks embedded within them. When such issues affect the equity of how the benefits of the federal system flow to its customers, however, there may be a need to allow for more flexibility in the structure of such arrangements, or shorter contract lengths, or mechanisms that maintain equitable relationships between customers classes, to allow for changing conditions that could significantly affect equity calculations and/or perceptions.

### Lesson learned: A change in approach to decision making is needed

BPA's culture is one in which we seek to find ways to say "yes" to a variety of requests from our stakeholders while also seeking to avoid rate increases. This frequently results in the agency taking substantial financial risks. From 1999 to 2001 we took on increasing load obligations and funding obligations while telling our customers and ourselves that we could do so without large rate increases. Market prices that departed radically from forecasts, and failure to keep costs to rate case levels translated to large rate increases and great financial stress. The lesson learned here is that we need to be rigorous, objective and realistic about the financial impacts of the obligations we take on, before we take them on. Moreover, with the increasing price volatility in wholesale electric markets, we are going to have to be more conservative about the amount of risk we take on in the future. BPA has gone beyond the limits of risk it can absorb in the face of the increased risk and uncertainty in the industry. We also need to make sure that our customers and others affected by our decisions understand the potential implications of the decisions we make. We also need to ensure that, to the maximum extent possible, our decisions are linked to long-term strategy and objectives that are well understood internally and have been well reviewed externally. This links to the next lesson learned.

### Lesson learned: Limits to risk BPA can assume

BPA has historically assumed and managed a significant amount of risk on behalf of its customers and others. This is inherent in our role and will continue. But we believe a key lesson is that the amount of risk to be managed in the region's power system has grown substantially in recent years, and the fraction of that risk that BPA can absorb has therefore gotten smaller. Risks have increased because of unprecedented market price volatility and unprecedented concerns and problems with credit, coupled with ongoing uncertainties about industry restructuring. BPA has gone beyond the limits of risk that it can take on in the face of these increases in risk and uncertainty.

### Lesson learned: Changes needed in internal management

We conclude that a number of other improvements are needed in how we operate internally. The process of defining these improvements will be ongoing, but the following are the major areas we have identified to date.

**A need for clear and steady strategy and objectives.** In the late 1990s, the Comprehensive Review of the Northwest Energy System defined a more limited role for BPA. During Subscription, in response to what we saw as strong regional desires, we turned away from the limited role envisioned in the Comprehensive Review and committed to serve 3,300 aMW of load in excess of the firm production capability of the federal system. In addition, we agreed to increase cash payments and energy deliveries to the IOUs to benefit their residential customers. Other interest groups also requested program expansions that increased our cost levels.

This was a fundamental change in the role BPA was to play in the Northwest energy system. As addressed above, there are some good things about how BPA accomplished this switch in role, but the rapid shift is also responsible for much of the huge rate increases and financial problems.

We need to determine the business model BPA should use in the post-2006 time frame, and the ongoing Regional Dialogue appears to be the proper venue for such a discussion. Having a clear and early understanding of what the region expects BPA to provide in the long term will allow BPA to deliver those benefits in the most efficient way. This clarity should allow for much more efficient development, management and tracking of systems to support those objectives. It should also enable clearer and more confident decision making by BPA's customers and their development of systems to support the conduct of their business, because BPA's decision making should be more predictable based on a more clearly articulated and stable set of objectives.

We also need to ensure that BPA's organizational structure, business systems and processes are tightly aligned around these long-term objectives, both to minimize costs and to maximize effectiveness.

**A need for enhanced business systems and processes**. The change in role described in the previous lesson learned also meant that we forced solutions onto existing business systems, structures and processes designed for a different business environment. This made it more difficult to create programs built on solid analysis. The rate system with its multilevel CRACs is far more complex than anything the agency or the region had devised previously. We are all still discovering some of the implications and results of that complexity.

In addition, our rate case accounting differs substantially from the accounting we use to collect and report actual costs, and this makes it hard to recognize and explain deviations from rate case financial expectations.

Specific enhancements are needed in the following areas:

- Effective monitoring of rate case cost assumptions against actual costs experienced in the rate period requires that relationships between rate case cost accounts and accounts used to budget and record actual expenditures be understood and documented within a set of consistently applied procedures to produce deviation reports for management review.
- Regular reports throughout the rate period of how BPA's actual costs compare with rate case assumptions should be prepared and communicated broadly to BPA's employees, customers and interest groups.
- Real-time course corrections in today's more complex risk environment demand more responsive and standardized methods for modeling, testing alternatives and monitoring results.
- The rate setting process involves many interdependent analytic steps that must be carefully followed and that became more challenging to complete under time pressures created by the rapidly changing events BPA encountered leading up to June 2001.

We must also place emphasis on bringing online and fully utilizing all modules of the Bonneville Enterprise System in order to assure that basic business systems work with a common data architecture and from a common data repository so that consistent and comprehensive tracking and reporting are possible.

**A need to better leverage analytical capability to support long-term objectives.** In the mid- and late 1990s, under the model proposed by the Cost Review, we cut our analytical resources substantially in the areas of rates, load forecasting and other areas. These changes reduced our ability to assure reliable, complete, timely and thoroughly coordinated analyses of the many complex rate and financial issues we encounter. This has made it difficult for the agency to develop a comprehensive view of BPA's financial picture, given the complexity of elements (including the CRACs and Slice) that contribute to it.

The overall lesson is that BPA needs to align its analytical resources to the type and scale of its long-term objectives. Adding significant numbers of analytic staff is not viable. Instead, we must better integrate and leverage our resources to assure robust, comprehensive and timely analysis in the face of an increasingly complex market and public policy considerations. Alternatives for organizing, staffing, developing and coordinating BPA's analytical capabilities should be carefully evaluated to determine the most effective support going forward.

**A need to improve risk management.** We have always had to deal with uncertainty because no one can accurately predict the weather, the performance of our generating asset base, the overall economy and the like. However, the West Coast energy crisis of 2000-2001 and the unfolding restructuring energy market introduced a range and level of uncertainty that neither the region nor we had ever experienced. For example, the creditworthiness of our customers and business partners was never a concern prior to the energy crisis, but BPA now faces $90 million of unpaid bills for sales to California and additional unpaid DSI bills. Another clear example is the price volatility we saw in 2000-2001 that was unprecedented. Though significant enhancements in risk analysis were done as part of the 2002-2006 rate case, still the sophistication of BPA's risk management has not kept up with the complexity of the business environment we faced.

More generally we also need to understand the appropriate balance between the risks that BPA is asked to absorb and the risks that are assumed by the rest of the region's utility industry. Again, the mechanism for determining those balances is the Regional Dialogue.

In 2002, we began a systematic study of our understanding and management of BPA's risks and we are now moving forward with actions to improve risk management across the agency. These actions will bring improvements to the systems, processes and procedures, and organizational structure for risk management.

**A need to improve skills and communications.** Our internal review has surfaced a number of needs for enhancement of executive and management skills and competencies. We need enhancements in risk management skills – both in risk analysis and in the use of risk analysis results by decision makers. Similarly, BPA needs to build its strength in financial analysis and use of financial analysis and reports for decision making. Also, though BPA has invested a great deal in management systems to ensure management to clear measurable targets, we still need to do better in this area.

We also need to work on communication. It is clear that we don't always make maximum use of our analytical skills because information from analysts distributed throughout the agency does not always flow smoothly from one group to another and up and down the reporting structure. Many BPA managers and staff feel that their views and ideas have not received an appropriate degree of consideration and that, if they had, better decisions would have been made. We need to explore this concern and make appropriate changes to address it.

## Conclusion

We believe that understanding and acting on these lessons learned, with understanding and input from those we serve in the region, will lead to greater assurance that BPA will continue to provide the benefits of the remarkable Federal Columbia River Power System.