2002 Annual Report of the Bonneville Power Administration

Cover photo

BPA fish biologist Andy Thoms (upper right) works with students from H.B. Lee Middle School finding and identifying invertebrates during a Salmon Watch session at Eagle Creek in Oregon.
photo by Sherry Lind

2002 Annual Report

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A word about this report

This report features employees from various parts of the agency. The writing and design were done in house. All photographs were taken by employees. The small photos were entries in an employee photo contest in 2002. Captions and photo credits are listed on page 50.

Performance Measures

Each year since 1995, BPA has selected a set of measurable goals that the agency as a whole is responsible for achieving. These targets act as indicators of overall agency success and determine the agencywide portion of the employee recognition program. In FY 2002, the agency fully met four targets of six targets and partially met the other two. Each target has a range of acceptable scores.

Finance

The agency met its very important target of controlling internally managed costs so they fell within the range of $1,105 million to $1,175 million. BPA also made its payment to the U.S. Treasury on time and in full although it failed to produce net revenues in the range from $75 million to $150 million.

Stakeholders

The target for the composite agency customer satisfaction index was to be in the range from 7.3 to 7.7. The result was 7.6 so the target was met.

The agency met the composite satisfaction index target for state/federal entities and constituents. The target was to have this satisfaction index fall within the range from 6.8 to 7.4; the result was 7.0. The agency did not, however, make its tribal government satisfaction index target. The score was 5.1 when the target was to be within the range of 6.1 to 6.4.

Internal Systems and Processes

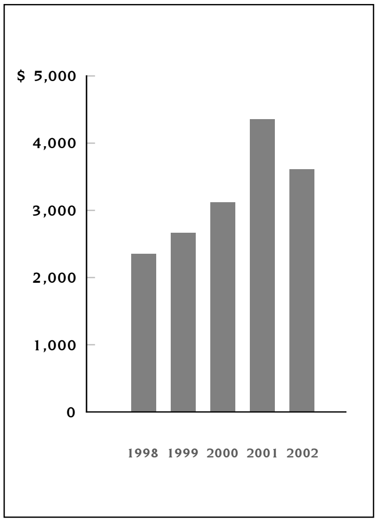
The target for high system reliability/sufficiency had two parts. The Transmission Business Line target was to have outage frequency and duration below limits based on past experience. The Power Business Line target was to have no involuntary curtailments of firm load due to inadequate power supply. Both targets were met.

The safety target was for recordable lost-time injuries to be in the range from 1.1 to 1.6 per 200,000 hours worked and for no fatal injuries to occur to BPA or contract employees working on BPA facilities. This target was reached. The rate of recordable lost-time injury was 0.9 per 200,000 hours worked, an improvement from the 1.1 result in FY 2001, and there were no fatal injuries. BPA's injury rate is significantly below the industry average.

Financial Highlights

Federal Columbia River Power System
As of and for the periods ended Sept. 30

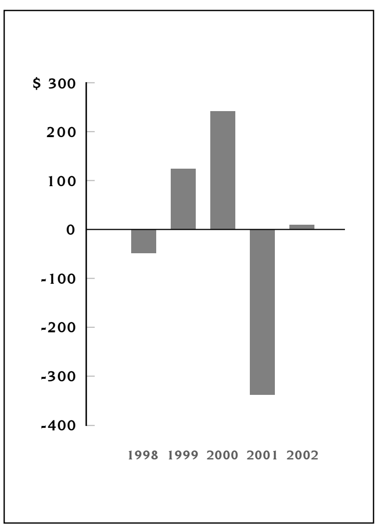
Total Operating Revenues
Millions of dollars



Operating Results
Thousands of dollars

	2002	2001
Revenues	$ 3,495,375	$ 4,230,792
SFAS 133 mark-to-market	38,354	47,877
Total operating revenues	3,533,729	4,278,669
Total operating expenses	3,171,954	4,115,670
Net operating revenues	361,775	162,999
Net interest expense	352,300	331,909
Net revenues (expenses) before the cumulative effect of SFAS 133	9,475	(168,910)
Cumulative effect of SFAS 133	—	(168,491)
Net revenues (expenses)	**$ 9,475**	$ (337,401)

Net Revenues (Expenses)
Millions of dollars



End of Fiscal Year
Thousands of dollars

	2002	2001
Total assets		
(net of accumulated depreciation)	**$ 16,511,999**	$ 16,770,530
Total capitalization and liabilities		
Accumulated net expenses	$ (211,676)	$ (221,151)
Federal appropriations	4,642,602	4,670,930
Capitalization adjustment	2,192,400	2,259,756
Long-term debt	2,770,441	2,688,542
Nonfederal projects debt	6,201,544	6,171,949
Other	916,688	1,200,504
	$ 16,511,999	$ 16,770,530

Letter to the President

Dear Mr. President:

The Bonneville Power Administration's highest priority now and into the near future is to regain its financial health.

The last two years have been marked by unprecedented price volatility in the West Coast energy market. In the 2001 fiscal year, BPA, along with the other utilities in the Pacific Northwest, was hit hard by a drought and unprecedented high prices for the power we had to buy on behalf of our customers. In FY 2002 we positioned ourselves to be net sellers to avoid those high prices. Unfortunately, when the power market crashed in FY 2002, we joined many other electricity suppliers in facing a tough year because of reduced revenues from our net secondary power sales.

Early in FY 2002, we looked at the changed market and projected a significant gap between our net power revenues and expenses in the current rate period (FY 2002-2006). By late summer that projection had risen to $1.2 billion.

We responded immediately to the projected shortfall by reducing our FY 2002 power-related expenses, and, where appropriate, deferring planned expenditures to a total of about $90 million from start of FY 2002 levels. We examined our spending projections for fiscal years 2003-2006 and identified about $348 million in highly probable expense reductions, deferrals and other actions. As part of that effort, we expect to remain at FY 2001 actual spending levels in power-related internal operating costs.

We are, however, maintaining programs that would allow us to reduce costs or generate revenues for the long term. These include demand-side management programs and investments in the hydro system and in Energy Northwest's Columbia Generating Station nuclear plant.

We also initiated a regional dialogue we called Financial Choices. We knew that we would have to make significant decisions about program levels and power rates and wanted a clear understanding of the relative value the region's citizens place on rates and program levels.

The stakes are high. We have identified over $500 million in additional expense reductions, deferrals and other actions. Reaching that level will require broad regional cooperation because a significant portion of our costs is tied to the benefits the agency provides to the region's ratepayers. We are, for example, buying substantial amounts of power during the current rate period because we are supplying more customers with more cost-based power than we had anticipated. Many customers came back to the agency two years ago to avoid the then-soaring power market. We are also providing hundreds of millions of dollars of increased benefits to the residential and small-farm customers of the region's investor-owned utilities through FY 2006. And we have maintained our legal commitment to help recover species, primarily salmon, listed under the Endangered Species Act.

It is clear that, as a result of the Financial Choices dialogue, we have emphasized expense reductions over rate hikes. Our customers made it quite clear that many of them are in very precarious financial condition and their consumers are having a very difficult time dealing with past rate increases. Further, Washington and Oregon have been alternating as the states with the highest unemployment in the nation.

We will do all that we can before we raise rates. A lot will depend on hydro conditions and the price we receive for our secondary power. But the rate structure currently in place includes a series of cost recovery adjustment clauses that were built into the rate case to cover risk. Instead of setting a five-year fixed rate as we normally do, our customers asked us to set our initial rate lower and to employ adjustment clauses to deal with risks of underrecovery. The alternative was a very high five-year fixed rate.

It is critical to understand that, while we are currently struggling with financial concerns, our customers understand that BPA's core generating and transmission assets continue to be an outstanding value. BPA's current financial difficulties stem from seeking to provide extensive public benefits during a time in the late 1990s when BPA was experiencing excellent secondary revenues. The agency and the Northwest Power Planning Council are jointly addressing how public benefits should be distributed from the BPA system after 2006 when BPA's current rates expire and there are opportunities for contract modifications. Customers are expressing substantial interest in pursuing long-term contracts with BPA post-2006 despite our current difficulties.

In the broader area of risk, it is abundantly clear that the entire industry has changed in ways no one anticipated. Up until two or three years ago, a hydro-based utility system such as BPA appeared to have a limited number of readily identifiable risks — primarily water conditions. Our power supply is free but highly variable. The continuing West Coast energy crisis demonstrates that no one in the electric utility industry has fully understood the ramifications of wholesale industry restructuring made possible by the National Energy Policy Act of 1992.

We realized that we have to broaden our view of what constitutes risk. We chose seasoned energy consultants to help us identify all major areas of vulnerability — including operations, market, credit, regulatory, cyber and physical. Those risks have also taken business concerns and regional responsibilities into account. We will soon produce a decision document on organizing and running our efforts to better manage risk of all kinds.

The attention BPA and the region gave to the agency's financial condition was a necessary and constructive effort that helped clarify the agency's role in the region. While the effort consumed significant resources, it did not prevent the agency from preparing for the future.

As part of our commitment to the Northwest, we're going to make a concentrated effort to advance infrastructure investment. We think that will be necessary to preserve reliability, to dampen power price volatility and to promote the economic well-being of the region.

We also are working with regional partners to create an RTO — a regional transmission organization — for the region that is consistent with the Federal Energy Regulatory Commission's (FERC's) Order 2000 but that also meets the specific needs of the Pacific Northwest. Our commitment to ultimately join an RTO is contingent on assuring the region and our customers that BPA's key principles, such as preserving the transmission system's benefits for our customers, are met. Currently, there is a great deal of debate, yet significant collaboration, over creating RTO West and implementing FERC's proposed standard market design. We will continue to constructively engage our customers, FERC-jurisdictional utilities and other stakeholders to find the right solution.

We are also reinforcing a businesslike approach to addressing our environmental problems. The most vexing problem is, of course, restoring fish species, primarily salmon, listed as threatened or endangered under the Endangered Species Act. We're developing management schemes so we're clear about what the goals are and how we are managing to those goals.

And, finally, we're working on our human resources — making BPA a great place to work. And I'm happy to report that, according to a survey conducted by the Office of Personnel Management, BPA may have the best work environment of all federal agencies.

As gratified as BPA management is by the employee view of the agency, we'd like to have the entire region feel that BPA is doing the best job possible for the region. By addressing our financial condition in a balanced way that prudently controls expenditures and rates, we believe we are offering the region real value. As long as we serve the public interest, we expect that BPA will continue to experience strong support for our vital role in the economic well being of the Pacific Northwest.

Sincerely,

Stephen J. Wright
Administrator and CEO

A truism in the electric power industry says that it isn't so much rising or falling prices that cause trouble, it is the unpredictability of volatile prices.

The entire West Coast can attest to the validity of that truism.

The West Coast energy crisis of 2000/2001 was caused by the first half of a period of unprecedented price volatility. During that time, power prices went from an average in the $25 per megawatt-hour range to an average of greater than $200/MWh while hitting $1,000/MWh at times. The disruption in the industry caused when utilities short on power had to buy at such unprecedented prices was widespread and commonly understood.

In FY 2002 the crisis continued because of an equally unprecedented swing in the other direction — prices dropped to single digits for a time and averaged in the mid-$20/MWh range.

Because many electric utilities sell at the wholesale level as well as buy, low prices can be as bad for them as high prices. Utilities that positioned themselves to be net sellers because they expected wholesale prices to be in the $200 range anticipated revenue that they are not receiving.

As in the 2000/2001 crisis, BPA was better positioned in FY 2002 than most utilities but was not immune to the consequences of the price volatility and water conditions affecting hydro output. The agency ended FY 2002 with net revenues of $9 million but drew down its reserves of $625 million by $437 million, leaving only $188 million.

BPA entered FY 2002 at a disadvantage. It nearly exhausted its Fish Cost Contingency Fund in FY 2001, and it lost storage in the Federal Columbia River Power System reservoirs because of the Northwest drought — 2001 was the second-lowest water year in the 61-year history of the system.

The agency also had increased commitments to its customers during FY 2002, the first year of the five-year rate period. It was purchasing power to augment its base system to cover the demands of public utilities that had signed to return to BPA during the energy crisis, and it had vastly expanded financial responsibilities to the investor-owned utilities as a result of the rate case. Still, the most significant variables in BPA's projected financial condition through FY 2006, the end of the current power rate period, are the revenue it will receive from surplus power sales and its susceptibility to less-than-average water conditions.

The options

BPA fared better in FY 2001 than most utilities because it attacked the expense problem by engaging the region in a demand-reduction campaign. BPA chose to enlist its customers and the region's industries and consumers in a campaign that emphasized conservation and load buy downs instead of power purchases. That effort was successful in limiting BPA's exposure to the extraordinarily high market.

Once again, BPA has reached out to the region to help reduce the impact of the current economic challenge. The magnitude of the problem is significant. Over the remaining four years of the current power rate period, were BPA to do absolutely nothing to address its deteriorating financial condition, the gap between the agency's revenues and expenses could approach $900 million even with the financial-based cost recovery adjustment clause triggered.

The agency will, of course, take action. The question is which actions and with what emphasis.

Reducing expenses — In FY 2002, the agency used expense reductions, expense deferrals and other actions to reduce expenditures by approximately $90 million from levels expected at the beginning of the fiscal year. These were thoughtful but quick responses employing such techniques as significantly reducing administrative costs, limiting hiring,

restricting contracting, reviewing travel budgets, managing debt and reducing spending on conservation augmentation and renewable resource projects.

Already these actions have brought some criticism from program constituencies. Because deeper cuts or significant rate hikes must be contemplated for the future, the agency decided to engage the region in a discussion of what it values in BPA's power services.

Raising power rates — When BPA and its customers agreed on the agency's power rate in June 2001, they opted to depart from the traditional five-year fixed rate because that power rate would have to have been very high to compensate for the risk of market uncertainty. Instead, they adopted the lowest-possible base rates and added three cost recovery adjustment clauses (CRACs) to cover risk, including that from market fluctuation.

These tools are very important in the current market climate. In fact, BPA used one of them in FY 2002. The year began with a 46 percent load-based CRAC (LB CRAC) in place to cover the additional load customers placed on the agency when more of them than expected opted to escape the market by returning their load to the agency. The LB CRAC contains adjustments to the base rate every six months to recover the cost of purchasing power to augment the agency's base federal supply. It is determined prior to each six-month period based on a forecast of loads and market prices. A true-up process takes effect after each six-month period to cover over- and undercollections. The LB CRAC applies to both Slice and non-Slice customers.

Late in FY 2002, BPA estimates showed that the financial-based CRAC (FB CRAC) would trigger with the beginning of FY 2003. It triggers for one year in addition to the LB CRAC adjustment if the Power Business Line's third quarter projection of year-end adjusted accumulated net revenue falls below a predetermined amount — negative $408 million in FY 2002. There is a limit on how much can be collected in each year. In FY 2003 that amount is $135 million. The amount actually collected is "trued up" based on audited actual financial results at the end of the year. The FB CRAC does not apply to Slice customers because they have their own true-up process to cover the actual costs of producing the power they receive.

To date, the safety net CRAC (SN CRAC) has not been triggered although it will be under consideration in FY 2003. It triggers independently of the FB CRAC if BPA forecasts a 50 percent or less chance it will not be able to meet its yearly obligation to the U.S. Treasury or if it actually misses a payment to any other creditor in the current fiscal year. The SN CRAC does not apply to the Slice product.

Each year BPA repays Treasury for the federal investment in building the FCRPS, plus interest. That payment in FY 2002 was $1.056 billion, which included a $266 million payment to retire federal debt early.

Choosing the right balance — BPA cannot rely solely on expense reductions or on power rate increases to eliminate its power revenue shortfall. Drastically reducing expenses would eliminate or significantly reduce programs the region values — fish recovery, conservation, renewable energy development and needed improvements to the region's power generation and transmission infrastructure. Raising rates significantly would undercut another public benefit — low electricity rates — and could harm an already weak regional economy.

While the BPA administrator makes the final decision, a regionwide Financial Choices discussion on power issues held during August was an important preliminary step toward forming that decision. During six public sessions, the various interests groups, utilities, tribes and consumers were encouraged to explain their positions and values to each other rather than to BPA. The goal was to develop a consensus about regional values that could help guide the administrator in his decision making. A decision as significant as this one has to be sustainable within the region, which means it must be consistent with the region's values.

Transmission infrastructure issues

Reliable power is one BPA benefit the entire region agrees on. The energy crisis of 2000/2001 forced the public to recognize the role of transmission in assuring reliability. The infamous Path 15 constrained path (transmission bottleneck) that prevented power in Southern California from reaching Northern California where it was desperately needed was an eye opener. People have come to understand that power reliability is as much a matter of available transmission as it is of available generation.

The Transmission Business Line took the issues of transmission adequacy, availability and reliability to the public in its Programs in Review meetings in July. The meetings reviewed Transmission's proposed program and spending levels in light of its ability to maintain an adequate and reliable transmission system. The meetings prepared the public and BPA's customers for the Transmission rate case that will occur during FY 2003 and cover FYs 2004-2005.

The Transmission Business Line is facing a significant backlog of investment because of earlier cost cutting. From 1992 through 1998, the TBL cut its planned capital investment and reduced its expenses and staff while using innovative technologies and control techniques to meet customer needs and market demand. Load growth and increased wholesale transactions used up the remaining capacity by 1999. Hence the need to review program and spending levels.

In many cases, capital projects are needed to meet current and expected new transmission service needs. About half the projects are to build new lines or to upgrade existing lines to maintain reliability and eliminate existing transmission path congestion that limits the flow of energy through the system. Other projects are to connect new generation or to replace aging lines and equipment. All these projects will contribute to restoring system operating margin so facilities and equipment can be taken out of service for maintenance.

BPA identified 20 projects as needing to be completed over the next ten years to assure reliable and adequate transmission. The agency assigned top priority to nine of those projects. The Infrastructure Technical Review Committee made up of experts from Northwest utilities evaluated the projects and each committee member found the 20 projects to be necessary and properly prioritized. Some of the projects to connect new generation were put on hold late in the year while generators gain permitting and financing for their plants.

BPA found strong support across the region for increased capital investments to maintain and improve the transmission system. The capital projects will pay for themselves over time through revenues from transmission transactions.

Despite its need to expand its capital program, the business line proposes to keep rates approximately level after reducing expenses significantly during FY 2002. During FY 2002, TBL reduced its expenses by $27.5 million (13 percent) from planned levels and anticipates increased FY 2002-2006 reductions through increased efficiencies and additional cost reductions.

BPA continues to examine and deploy advanced control technologies and approaches such as Flexible AC Transmission Systems where appropriate. While BPA believes that it employed all cost-effective "nonwires" solutions to transmission limitations during its earlier cost-cutting years, it has asked the region to study several projects to assure that it has not overlooked any less expensive nonwires solutions or those with a lower environmental impact. The agency intends to work with a regional roundtable as one source of insight on nonwires approaches. Nonwires approaches use demand reduction, conservation and distributed generation to reduce the need for new transmission lines.

Regional transmission organization

The Northwest's proposed regional transmission organization — RTO West — passed two major milestones in FY 2002.

BPA and the other utilities working to create the RTO — Avista Corp., British Columbia Hydro and Power Authority, Idaho Power Co., Nevada Power Co., NorthWestern Energy, PacifiCorp, Portland General Electric Co., Puget Sound Energy Inc. and Sierra Pacific Power Co. — submitted their "stage 2"

filing to the Federal Energy Regulatory Commission in March. The group asked FERC to rule that, pending further refinements, the proposal satisfies the minimum characteristics and functions that FERC has established for an RTO.

On Sept. 18, 2002, FERC ruled on the filing. The commission praised the group for its work and said, "As discussed in this order, the hard work of all parties has resulted in a proposal that, with some modification and further development of certain details, will satisfy not only the Order 2000 requirements, but also can provide a basic framework for a standard market design for the West."

The full implications of the ruling, with its approvals, requests for modifications, rejection of some provisions and deferrals of other provisions, are undergoing extensive review and debate within the region. Regional stakeholders continue to refine the proposal in a way that addresses the feedback from FERC while protecting the benefits of our unique hydro-thermal system in the Northwest.

BPA, which is not under the jurisdiction of FERC on RTO matters, has been participating in the RTO West effort to assure that it develops in a way that will reflect Northwest values rather than in a way that is more reflective of other regions. While the agency is committed to developing a workable RTO, the agency will not make a final decision on whether to join until it is assured that BPA's principles are met. It will be some time before that decision needs to be made. BPA believes it is imperative to take the time needed to develop an RTO proposal that's right for the region.

Conservation

Conservation was a cornerstone of BPA's highly successful FY 2001 demand reduction effort. That success was recognized this year when the Peak Load Management Alliance recognized BPA with its 2001 achievement award for a government agency. The award was in recognition of the

10,000 megawatt-hours of voluntary load curtailment and $2 million in savings from the Demand Exchange Program.

The solid work continued during FY 2002 as the agency exceeded many of its conservation program goals. The goal was to sign up 60 average megawatts under Conservation Augmentation contracts; 70 were brought under contract. The Conservation Augmentation group projected that each megawatt captured would cost $3 million, but new acquisitions are coming in at about $1.5 million. The goal was to deliver 25 average megawatts from all programs; 44 aMW were captured and at lower cost than projected.

Over the last 20 years, BPA has acquired more than 800 average megawatts of conservation — enough energy to power the city of Portland.

The Energy Efficiency group branched out in FY 2002 through pilot programs supporting two new initiatives. Most conservation will come from municipal, institutional, industrial and commercial facilities. Consequently, Energy Efficiency partners are focusing on restaurants and municipal water and wastewater treatment plants. BPA facilitated five water projects that gained 84 percent of the predicted energy savings.

BPA also supported an innovative conservation effort called Save a Watt. BPA leveraged its investment with in-kind support from advertising agencies and television stations to mount a successful campaign to encourage citizens to adopt conservation as a personal commitment.

The year-long ENERGY STAR™ Compact Fluorescent Lamp Coupon Campaign ended in December with over half a million CFL coupons being redeemed in the first quarter of FY 2002. This was equivalent to 4.52 aMW of energy savings. The agency's partners in market transformation were pleased as the campaign wound down with over a million free CFLs mailed out and over 6.5 million sold throughout the region.

In September, BPA and its partners displayed a Zero Energy manufactured home in Spokane, Wash., and then sited it in Idaho at the Nez Perce Tribal Fish Hatchery. With an array of partners, BPA demonstrated that an energy-efficient manufactured home is feasible for builders and buyers.

The Energy Web team continued building the foundation for the grid of the future. BPA teamed with several partners on the installation of the country's first combined heat and power application of a 30 kilowatt microturbine. Fuel cell testing continues with ten beta cells operated by customer utilities.

Renewable power

BPA is buying over 250 MW of power from new renewable resources, including six wind, one geothermal and two solar projects and is considering another 580 MW of wind power. Output from one wind project and one solar project was added in FY 2002.

One of the agency's major contributions to wind development in the Northwest is a change in transmission charges that could have been a major impediment to wind development. The problem with wind generation is that it is difficult to predict. That quality poses significant challenges for the transmission system because it makes it difficult to balance supply and demand. The Transmission Business Line charges generators the greater of BPA's incremental cost for energy plus 10 percent or a penalty of 100 mills per megawatt-hour if the energy generator delivers less than an amount within a specified band of what it was scheduled to deliver. That penalty made wind power more expensive than it would otherwise be. To remedy the problem, TBL ran a brief 7(i) rate case to eliminate the 100 mill penalty charge for wind. The Federal Energy Regulatory Commission approved the change effective Oct. 1, 2002. Wind generators must still pay for any power BPA must buy to make up for a shortage in what is delivered plus 10 percent.

The agency's commitment to renewable resources and sustainability also applies to the way it does business. BPA renewed its membership in the Federal Network for Sustainability in FY 2002. The network of six participating federal agencies focuses on expanding the market for green power, increasing the use of renewable energy and developing

and using environmental management systems. The network recognizes BPA as a model agency for its leadership in green power purchases, sponsorship of green power workshops, work with other federal agencies in energy efficiency and participation in a green power initiative.

In June, BPA cosponsored the largest-ever wind energy conference, WINDPOWER 2002, in Portland. Appropriately, BPA donated "green tags," credits equivalent to clean energy, in an amount equal to the conference's energy consumption. The agency cosponsored the third annual Northwest Renewable Energy Festival in Walla Walla, Wash., in September and sponsored an Earth Day Expo at the Oregon Zoo in Portland in April.

As part of its commitment to energy conservation and renewable energy, BPA helped fund a report "Poised for Profit: Clean Energy to Power Next High-Tech Job Surge in the Northwest." The report sees the Northwest as uniquely positioned to develop technologies for the clean energy industry. In following up on the report, BPA helped fund the Northwest Energy Technology Collaborative. The collaborative's goal is to position the region as a recognized leader in innovative research, education and product development for energy technology markets around the world.

BPA also collaborated on the Northwest's largest photovoltaic solar facility. The White Bluffs Solar Station is a joint effort of Energy Northwest, BPA, the Bonneville Environmental Foundation and the Department of Energy. BPA will integrate the power produced by the 38.7-kilowatt direct-current plant into its system. The Bonneville Environmental Foundation will sell the environmental attributes (displaced air pollution and green house gas emissions) as a "green tag" product to buyers who want to offset the negative environmental effects of their own power consumption.

Fish and wildlife programs

FY 2002 marked the first year BPA's fish program completed a full cycle of actions required under the National Marine Fisheries Service and U.S. Fish and Wildlife Service 2000 biological opinions on how the FCRPS should be operated to help recover anadromous and resident fish populations. Working with the U.S. Army Corps of Engineers and the Bureau of Reclamation, BPA completed a one-year implementation plan for FY 2002 and a five-year implementation plan for FYs 2002-2006, which built on the plans created in FY 2001. New this year was the first annual report on the previous year's accomplishments under an implementation plan.

While the progress report covered FY 2001, it is an important milestone and, for a couple of reasons, suggests the success that can be expected for FY 2002 — the year saw nearly normal water conditions in the Columbia River Basin, as opposed to the near-record low water in FY 2001, and, as a result, BPA and its federal partners in river operations were able to conduct the full range of fish operations.

Despite the low stream flows and the need to declare power emergencies and limit spill in FY 2001, the program is making good progress. The NMFS "findings" for the implementation plan said that 173 of 199 measures required

in the biological opinions are on track to meet initial program benchmarks in 2003.

Salmon returns confirmed that the program was on track — they were, for the most part, second only to FY 2001's runs since record keeping began in 1938. We anticipate that next year's runs will also be very good despite the low stream flows in FY 2001. Precocious male salmon that return a year earlier than most of the run arrived in surprisingly strong numbers, which suggests that the fish transportation program is successful and that next season's returns will also remain high.

BPA meets its obligations to fish and wildlife under the 1980 Northwest Power Act by funding a fish and wildlife program established by the Northwest Power Planning Council. The Council and BPA worked together on a new integrated approach that also includes BPA's obligation under the Endangered Species Act. The Council has divided 90 Columbia River subbasins into 11 "provinces" for scientific review to help define ESA issues and objectives and to establish strategies for meeting those objectives. The Council is using a three-year planning cycle to get through all 11 provinces. Funding decisions this year included the Columbia Plateau, Mountain Columbia, Blue Mountain and Mountain Snake provinces. The Mountain Snake Province, for example, includes the Salmon and Clearwater river subbasins in Idaho.

BPA has a two-fold responsibility in the wildlife arena — it must continue to fulfill its obligation under the 1980 Northwest Power Act to acquire habitat to replace that lost to the construction of the region's federal dams, and it must meet the agency's Endangered Species Act responsibilities to species listed as threatened or endangered.

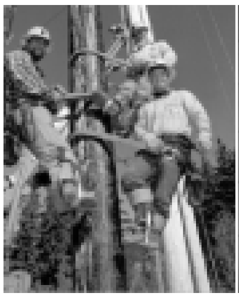
With the advent of subbasin planning, the wildlife and fish programs are becoming even more integrated. Fish recovery is based on the "all-H" strategy. That means recovery efforts cover hydro operations, hatcheries, harvest and habitat. Subbasin planning emphasizes the habitat H. Good habitat programs benefit both fish and wildlife.

One of BPA's large land acquisitions in FY 2002 demonstrates how both fish and wildlife can benefit from the same purchase. When BPA bought the 4,295-acre Forrest Ranch on Oregon's John Day River, it protected several miles of spawning habitat on the mainstem and Middle Fork that will benefit spring chinook and listed summer steelhead. Tributary streams will provide spawning and rearing habitat for listed bull trout. The agency transferred ownership of the ranch to the Confederated Tribes of the Warm Springs Reservation. The tribes will manage the property.

The ranch includes far more than stream beds and the neighboring riparian habitat — it also includes upland habitat that will further BPA's wildlife responsibilities by providing a home for species such as sharp-tailed grouse, antelope and turkeys.

Since 1990 BPA has, through purchase of land or conservation easements, protected tens of thousands of acres. The agency has protected approximately 1,730,029 acres of land specifically for wildlife. Land under protection specifically for fish is sometimes measured in acres and sometimes in river miles. The current total is approximately 14,604 acres and 420 river miles. These habitat acquisitions benefit such listed species as bull trout, steelhead, Columbia white-tailed deer, pygmy rabbit and bald eagle. They also benefit such nonlisted species as rainbow and cutthroat trout, bobcats, river otters, downy woodpeckers and song sparrows.

The effectiveness of BPA's programs was recognized nationally when the agency and its partners received a U.S. Forest Service award for their "Collaborative Aquatic Stewardship" on the Wind River watershed restoration project.



BPA financed the cooperative program on the Columbia River tributary in Washington. The project assessed the basin's habitat, planted tens of thousands of cedar and willow trees and placed hundreds of logs on the bank to provide stability. The partners also removed culverts and installed corrosion-control matting. The project involved school districts, utilities, the state extension service and local landowners.

Tribal relations

During FY 2002, BPA made some internal changes to strengthen its ability to communicate with the tribes and to respond more quickly and effectively to their concerns and issues. The agency added tribal account executives both to its Transmission Business Line and its Power Business Line and a liaison to the Fish and Wildlife division to complement the work of the Corporate Tribal Relations group.

The Tribal Relations program transitioned from providing the business lines and Environment, Fish and Wildlife with communication and issue resolution activities to policy oversight and internal and external training for BPA and the tribes. During the year, the Tribal Relations program staff continued to assist the business lines as requested, educate BPA employees on the agency's tribal policy and provide outreach to tribal communities. In the new Tribal Relations structure, the Tribal Relations program staff work with the region's tribes on broad agencywide policy issues while the business line account executives and the Fish and Wildlife liaison focus on specific substantive issues related to the business practices of their individual groups.

The complexity of the BPA/tribal relationship is evidenced by the addition of BPA's first tribal utility to the agency's customer list. The Umpqua Tribal Utility Cooperative signed a contract to purchase five average megawatts of power to serve tribal loads in southern Oregon. The Cow Creek Band of the Umpqua Tribe of Indians formed the utility to serve the tribe's casino, hotel, conference center, truck and travel shop and other commercial and residential customers on tribal land.

The region's tribes examined the possibilities of developing power generation on tribal lands at the Tribal Energy and Economic Development Conference in Portland that BPA cosponsored with the Bureau of Indian Affairs and the Affiliated Tribes of Northwest Indians/Economic Development Corporation. The tribes, public agencies and private developers discussed possible partnerships and addressed issues such as financing, risk management and transmission interconnection.

More traditional issues were addressed at the fifth annual meeting on managing historic and cultural resources at Federal Columbia River Power System reservoirs. At the BPA-sponsored event, tribes and federal agencies reviewed progress in preserving historical, archeological and cultural treasures. The tribes participated quarterly at reservoir cooperating groups. Discussions covered the impacts of system operations, memorandums of understanding,

programmatic agreements and resolution of tribal contract concerns.

BPA and the tribes continue their close collaboration in fish and wildlife programs. The Columbia Basin tribes and the BPA liaison were heavily involved in biological opinion implementation plans, subbasin planning efforts and the ongoing Northwest Power Planning Council fish and wildlife ESA/mitigation processes and contracting issues.

During the year, the tribes were involved in many of the Transmission initiative projects. The tribes potentially affected by the construction projects were identified and contacted early in the planning process. They successfully negotiated contracts for cultural resource analysis in project environmental documents.

The Transmission Business Line and the tribes were successful in working through ongoing regional transmission organization issues. In FY 2002, TBL provided the Affiliated Tribes of the Northwest Indians with two grants for continued representation and tribal presence in their continuing discussions.

International relations

BPA and the U.S. Army Corps of Engineers are the "entity" that represents the U.S. in the continuing relationship based on the 1964 Columbia River Treaty with Canada. That treaty

defined how the upper Columbia River would be developed and how the power and flood control benefits of three large storage projects in British Columbia would be divided.

Issues surrounding that treaty continue to evolve with changes in the availability of water and transmission. In FY 2002, BPA and B.C. Hydro signed a one-year extension of an existing nontreaty storage agreement covering water in Kimbasket Lake behind Mica Dam. The reservoir contains 5 million acre feet of water beyond that called for in the treaty, which makes it nontreaty storage. B.C. Hydro will use the extension to conduct a water use study to determine if it needs the water in the near future. If B.C. Hydro does need the water, that would put constraints on American use of that storage, which has been very valuable over the past years because of drought and fish operations.

The stipulations of the Canadian treaty also come to bear on transmission issues as Canada's half of the increased downstream power benefits from the Canadian storage must be returned to Canada. The limitations on transmission capacity in the Seattle area are making that return difficult. However, elimination of this constraint on transmission capacity is included in the current transmission infrastructure program.

High-performing organization

Many signals indicate that BPA's high-performing organization status is reasonably strong and continues to improve. Most fundamentally, the two employee surveys performed in FY 2002 provide strong evidence that BPA is on a successful path. In February, BPA participated in the Office of Personnel Management O*rganizational Assessment Survey*, and OPM concluded that BPA's scores were "outstanding." The survey provided information in 17 categories of organizational performance. BPA set new benchmark high scores within the federal government in 12 of those categories and tied previous highs in two categories.

The survey also provided a benchmark against a sample of large private sector companies, and BPA exceeded those benchmarks in almost all areas.

In June, BPA repeated its Great Place to Work® survey, and results showed continued strong improvement from the previous two years.

Beyond 2006

Even as BPA was dealing with serious economic issues that will last the duration of the current power rate period, the agency cosponsored a series of regional public meetings in September and October of 2002 on the way the costs and benefits of the FCRPS should be allocated after FY 2006.

At various times during the year, representatives of the direct-service industries (primarily aluminum companies) and both public and investor-owned utilities came to the agency to request that it make clear how those federal costs and benefits will be allocated after the current rate period ends with FY 2006. The customers argued persuasively that they need to know in advance of FY 2007 what their share of the power will be so they can better manage their power supply needs.

In April a group of utility representatives presented the agency with a draft plan for the post-2006 allocation. The proposal contained significant changes in the "Slice" power product and the allocation of benefits to the residential and small-farm customers of the IOUs. BPA and the Northwest Power Planning Council joined together to solicit proposals from all interested parties. As the fiscal year ended, BPA and the Council were holding a series of public meetings to encourage dialogue over the various proposals. The administrator will present the agency's own proposal in early calendar year 2003 and then hold regional hearings to gather comment on it.

All proposals will be evaluated against five principles. Proposals must: 1) preserve or enhance the long-term and diverse public benefits of the FCRPS for the region; 2) provide policy outcomes that are enduring under a range of political and economic conditions; 3) provide no additional risk to the U.S. taxpayer or to the Treasury; 4) avoid legislative changes and minimize legal risks; and 5) provide clarity regarding BPA load obligations post-2006.

Profile

The Bonneville Power Administration is a federal agency under the Department of Energy. Based in the Pacific Northwest, the agency markets power from 31 federal hydro projects, one nonfederal nuclear plant and several other nonfederal power plants. BPA also operates and maintains about three-fourths of the region's high-voltage transmission. About 45 percent of all the electric power used in the Northwest comes from BPA.

BPA is a self-funding agency that covers its costs by selling its services wholesale to the region's public utilities, municipalities, investor-owned utilities and some large industries. BPA also sells or exchanges power with utilities in Canada and the western United States. Its service area includes Oregon, Washington, Idaho, western Montana and small parts of Wyoming, Nevada, Utah, California and eastern Montana.

BPA is dedicated to providing public service. In addition to keeping rates low by selling at cost, BPA also promotes energy efficiency, renewable energy and new technologies. The agency funds the region's efforts to protect and rebuild fish and wildlife populations in the Columbia River Basin and works in partnership with others to ensure protection of the region's environment.

Financial Section

Results of Operations

2002 Compared to 2001

The 2002 operating revenues were $3,534 million, a decrease of $745 million or 17 percent from the previous year. Revenue from power sales decreased $156 million or 4 percent. This was the result of lower market prices for discretionary sales of surplus power. Average prices decreased to $26 dollars per megawatt from $101 dollars per megawatt the prior year. U.S. Treasury Credits for Fish decreased 94 percent from 2001 to 2002. Due to the improved water conditions and more normal market prices for purchased power the 4(h)(10)(C) revenue credit decreased to $38 million compared to $354 million in 2001. Criteria did not permit use of the Fish Cost Contingency Fund whereas $247 million was drawn from the fund during 2001. Net revenues were $9 million in 2002, an increase of $347 million from 2001 net expenses.

2001 Compared to 2000

The 2001 operating revenues were $4,279 million, an increase of $1,212 million or 40 percent from the previous year. Despite a very low water year, revenue from power sales were up primarily because market prices for discretionary power sales increased to $101 dollars per megawatt from the previous year average of $29 dollars per megawatt. U.S. Treasury Credits for Fish increased over 10 times from 2000 to 2001. Due to the drought conditions and high market prices for purchased power the 4(h)(10)(C) revenue credit increased to $354 million. The credit computation is subject to an annual true up. Furthermore, as a result of the market conditions BPA accessed the Fish Cost Contingency Fund for the first time in history. The $325 million fund is for excess payments electric ratepayers have made for salmon recovery in prior years. BPA accessed the fund for an additional $247 million in credits, leaving the fund balance at $78 million. Net expenses were $337 million in 2001, a decrease of $578 million from 2000 net revenues. Approximately one-third of the loss was the result of adoption during the year of a new industry accounting standard, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). The changes as a result of SFAS 133 reflect an accounting only adjustment with no corresponding cash impact. Excluding the SFAS 133 adjustments, net expenses for 2001 were $217 million.

2000 Compared to 1999

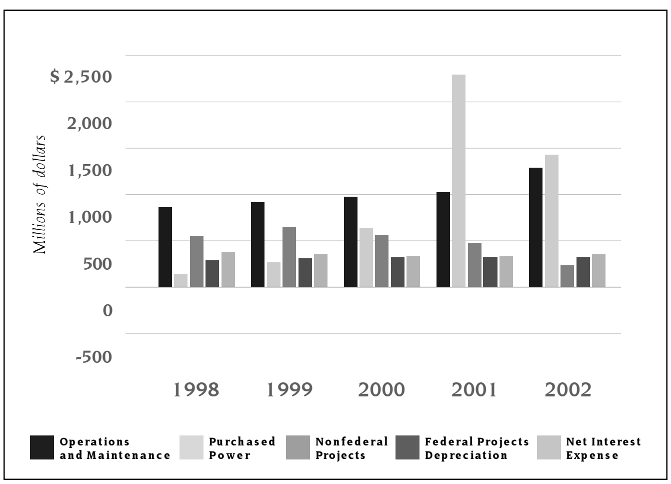
The 2000 operating revenues were $3,067 million, an increase of $448 million or 17 percent for the previous year. Despite a slightly below-average water year, revenues were up primarily because market prices for discretionary power sales increased to $29 dollars per megawatt from the previous year average of $20 dollars per megawatt. Miscellaneous revenues of $103 million included $26.8 million for the sale of property acquired as a result of settlements with Tenaska. Net revenues were $241 million in 2000, an increase of $118 million over 1999 and the highest net revenues in nine years.

Expenses

In 2002, total operating and net interest expenses were $3,524 million, a decrease of 21 percent compared to 2001. Total operating and net interest expenses increased by $1,622 million in 2001 to $4,448 million, an increase of 57 percent over the previous year. Total operating and net interest expenses increased by $330 million in 2000 to $2,826 million, an increase of 13 percent over the previous year. Operating expenses have fluctuated primarily because of changes in purchased power expense.

In 2002, operations and maintenance costs increased by $297 million from the previous year, or 29 percent. Investor-owned utility subscription settlement agreements and increased budgets for fish and wildlife and resource conservation management were the primary factors driving the increase. Operation and maintenance costs rose by $46 million in 2001, an increase of 5 percent. Higher operations and maintenance expenses for BPA and the Columbia Generating Station nuclear project were the primary cause for the increase. Operation and maintenance costs rose by $63 million in 2000, an increase of 7 percent. Higher operations and maintenance expenses for BPA were the primary cause for the increase.

Expenses by Category



Purchased power decreased by $1,009 million, or 44 percent to $1,287 million in 2002. Megawatt-hours purchased decreased 15 percent in 2002 from 2001 levels. The average cost of purchased power decreased from $90 dollars per megawatt in 2001 to $61 dollars per megawatt in 2002. Purchased power costs increased by $1,663 million, or 263 percent, to $2,296 million in 2001. Megawatt-hours purchased increased 137 percent in 2001 from 2000 levels. The average cost of purchased power increased from $57 dollars per megawatt in 2000 to $90 dollars per megawatt in 2001. Purchased power costs increased by $368 million, or 139 percent, to $633 million in 2000. BPA had to purchase more power in the spring when colder than normal weather kept the snowpack from melting and again in the summer when water was spilled for fish operations, which reduced generation capacity. Megawatt-hours purchased increased 6 percent in 2000 from 1999 levels. The average cost of purchased power increased from $28 dollars per megawatt in 1999 to $57 dollars per megawatt in 2000.

In 2002 debt service on nonfederal projects decreased by $243 million, or 51 percent, from $473 million in 2001. In 2001, debt service on nonfederal projects was $473 million, a decrease of $87 million, or 16 percent, compared to 2000. Selective redemption of bonds at Energy Northwest allowed the free up of bond reserves that were used to reduce current debt service. In 2000, debt service on nonfederal projects was $561 million, a decrease of $90 million, or 14 percent, compared to 1999, primarily because funds were released from certain debt service reserve accounts.

Federal projects depreciation was $335 million in 2002, $323 million in 2001, and $320 million in 2000.

Net interest expense was $352 million in 2002, an increase of $20 million compared to 2001. The increase was a result of interest paid on redemption of bonds and less allowance for funds used during construction. Net interest expense was $332 million in 2001, down $3 million from the prior year. Net interest expense was $335 million in 2000, a decrease of $21 million from the previous year. The decrease was a result of higher interest income due to higher cash balances during the year and lower interest rates on bonds.

Critical Accounting Policies

The accounting policies for the Federal Columbia River Power System are disclosed in the first note to the financial statements beginning on page 30.

Financial Condition

At Sept. 30, 2002, BPA's year-end financial reserves were $188 million — consisting of $149 million cash and $39 million for deferred borrowing authority. At Sept. 30, 2001, BPA's year-end financial reserves were $625 million. BPA's financial reserves at the end of fiscal 2000 were $811 million.

BPA made its annual payment of $1,056 million to the U.S. Treasury in 2002, making it the nineteenth consecutive year in which BPA has made its payment on time and in full. The payment consisted of $505 million for principal and $483 million in interest for the federal investment in the Federal Columbia River Power System. BPA also paid $55 million in contributions to the Civil Service Retirement System and $13 million for other obligations. Payments made in 2001 and 2000 were $729 million and $732 million respectively. This year's principal payment also included $266 million to repay Treasury borrowing in advance of its due-date.

The Rates section below discusses the Cost Recovery Adjustment Clauses (CRACs) that are used to mitigate risk and increase the probability of meeting the U.S. Treasury payments.

Rates

The fiscal year ended Sept. 30, 2002, was the first year of operation under new power and transmission contracts and associated rates. FERC granted interim approval for proposed Power rates on Sept. 28, 2001, for fiscal years 2002 through 2006, 96FERC 61,360 (2001). Those rates include several risk mitigation tools. The primary tools are three Cost Recovery Adjustment Clauses (CRACs). The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. There are three sets of conditions in which rate increases under the CRACs may trigger. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA incurs costs for meeting or reducing loads that were not included in the rate case. The second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of accumulated net revenues is below a predetermined threshold. The third is the Safety-Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has missed or reasonably expects to miss a payment to the Treasury or another creditor.

On Oct. 1, 2001, implementation of the LB CRAC caused BPA's rates to increase approximately 46 percent for the first half of fiscal 2002 compared to base rates. The LB CRAC percentage changes every 6 months. The increase was 41 percent for the second half of fiscal 2002. The LB CRAC percentage will be revised for the six-month periods beginning Oct. 1, 2002 and April 1, 2003. The August forecast of the generation function's accumulated net revenues triggered the FB CRAC, and will result in a one-year rate increase beginning Oct. 1, 2002 of approximately 11 percent for most of the requirement rates on top of the revised levels of the LB CRAC. SN CRAC did not trigger in fiscal 2002.

In addition to the CRACs, BPA established contracts and rates for a "Slice of the System Product." The basic premise of the product is that a purchaser pays a fixed percent of BPA's power costs in exchange for a fixed percent of generation and capabilities.

Financing

To finance capital programs such as transmission system development, conservation, and fish and wildlife enhancement, BPA is authorized to borrow up to $3.75 billion from the U.S. Treasury. At the end of 2002, BPA's debt in this category totaled $2,770 million — an increase of $82 million from the prior year. Long-term debt was $2,688 million at the end of 2001.

BPA began directly funding operation, maintenance and replacement of U.S. Army Corps of Engineers generation facilities in 1999 and Bureau of Reclamation generation facilities in 1997 as a result of new legislation and agreements. For costs not directly funded, the Corps of Engineers and Bureau of Reclamation use federal appropriations for new construction and replacement investments at the dams they operate. These appropriations, like BPA's borrowings, are to be repaid to the U.S. Treasury by BPA. The total remaining to be paid was $4.6 billion and $4.7 billion at the end of 2002 and 2001, respectively.

In 1997, the U.S. Treasury approved BPA's implementation of the BPA Appropriations Refinancing Act (Refinancing Act). The Refinancing Act was included in the Federal Omnibus Appropriations Act signed by President Clinton in April 1996. The net effect of the Refinancing Act returns about $100 million more to the U.S. Treasury in net present value than it would have received under BPA's old payment schedule. The Refinancing Act enhances BPA's long-term rate stability by mitigating the risk of higher interest costs that could have resulted from earlier repayment reform proposals. A reduction of federal appropriations debt of $2.5 billion was recorded in 1997 due to the Refinancing Act, replacing low interest rate appropriated debt with an equitable amount of debt bearing current market rates of interest. The capitalization adjustment of $2.5 billion will be amortized, using the effective interest method, over the life of the appropriations.

BPA owes another $6.2 billion to nonfederal sources for financing three Energy Northwest nuclear projects and several smaller generation and conservation investments. BPA backs bonds issued by others in the capital markets to finance these projects.

Three rating agencies continued to maintain high credit ratings for BPA-backed Energy Northwest bonds in 2002. Moody's Investors Service maintained a rating of Aa1, the second highest possible rating. Fitch IBCA, while maintaining their AA rating, placed the bonds on Rating Watch Negative. This was primarily due to increased concerns regarding the level and potential duration of net losses at BPA. Standard & Poor's affirmed their AA- rating with a stable outlook on the BPA-backed bonds. However, they indicated that there could be rating implications if BPA decides to forego the authorized CRAC mechanisms that they believe will likely be necessary to bring BPA back to a healthy financial position.

Market Risk

As a result of short-term sales commitments, short-term purchase commitments and written call option contracts, BPA is exposed to market and credit risks resulting from adverse changes in commodity prices and market conditions. Commodity market risk is a consequence of writing options to third parties, entering into fixed price sales and purchase commitments, and owning and operating generation facilities. Credit risk stems from potential nonperformance of contracts by counterparties.

Selected Quarterly Information *(unaudited)*

3 months ended — Thousands of dollars

	Dec 31	Mar 31	Jun 30	Sep 30	Totals
2002					
Revenues	$ 916,329	$ 853,649	$ 795,947	$ 929,450	$3,495,375
SFAS 133 mark-to-market	(48,066)	49,385	13,477	23,558	38,354
Operating revenues	$ 868,263	$ 903,034	$ 809,424	$ 953,008	$3,533,729
Operating expenses	856,924	790,533	661,041	863,456	3,171,954
Net interest expenses	87,037	100,278	85,833	79,152	352,300
Net revenues (expenses)	**$ (75,698)**	**$ 12,223**	**$ 62,550**	**$ 10,400**	**$ 9,475**
2001					
Revenues	$ 788,313	$1,322,994	$ 851,539	$1,267,946	$4,230,792
SFAS 133 mark-to-market	(292,720)	345,035	216,270	(220,708)	47,877
Operating revenues	495,593	1,668,029	1,067,809	1,047,238	4,278,669
Operating expenses	887,606	1,177,963	845,332	1,204,769	4,115,670
Net interest expenses	81,459	82,841	82,345	85,264	331,909
Net (expenses) revenues before cumulative effect of SFAS 133	(473,472)	407,225	140,132	(242,795)	(168,910)
Cumulative effect of SFAS 133	(168,491)	—	—	—	(168,491)
Net (expenses) revenues	**$ (641,963)**	**$ 407,225**	**$ 140,132**	**$ (242,795)**	**$ (337,401)**
2000					
Operating revenues	$ 687,487	$ 788,406	$ 629,015	$ 962,078	$3,066,986
Operating expenses	471,551	509,155	628,583	882,070	2,491,359
Net interest expenses	86,479	83,902	82,392	81,877	334,650
Net revenues (expenses)	**$ 129,457**	**$ 195,349**	**$ (81,960)**	**$ (1,869)**	**$ 240,977**

Management of market risk is critical to the success of BPA. Risk management processes, policies and procedures have been established to monitor and control these market risks. BPA manages its risk on a portfolio basis subject to parameters established by executive management and a risk management committee. To ensure compliance with the policies, individuals, who are independent of the group that creates and manages these risk exposures, monitor market risk measures.

BPA measures the market price risk in its portfolio on a daily, weekly, and monthly basis using net revenue at risk (NRaR), mark to market (MTM), value at risk (VAR), Monte Carlo simulation and other methodologies depending on the part of the portfolio. The quantification of market risk using these methods provides a consistent measure of risk across the energy market in which BPA buys and sells. The use of these methods requires a number of key assumptions including hydro/price correlations, the selection of a confidence level for expected losses, the holding period for liquidation, and the treatment of risks outside the methodology, including credit risk and event risk. These methods provide an estimate of reasonably possible net revenue outcomes that would be recognized on its portfolios assuming hypothetical movements in future market prices and is not necessarily indicative of actual results that may occur.

In addition to using market price risk measures, BPA performs regular scenario analyses to estimate the economic impact of a sudden change in supply. Unlike many of its industry counterparts, BPA's principal market activity is the sale of surplus inventory rather than the purchase and sale of electricity to earn trading revenues. Therefore, the tests critical to trading organizations (i.e. amount of risk to carry over very short time frames) are considered less important than regular and rigorous analysis of the consequences of a range of hydro supply conditions. Experienced business and risk managers use the results of the hydro supply scenario analyses and the market price risk measures in conjunction with their professional judgment to capture additional market-related risks, including credit and event risk.

In response to market price risk, futures, swaps and options may be used to alter BPA's exposure to price fluctuations.

BPA mitigates credit risk by insisting that counterparties and marketers are significant industry companies that are considered financially strong. BPA performs an initial financial review of new counterparties and establishes credit limits based on the results of that review. Reviews and credit limits are updated regularly to reflect the current financial conditions of each counterparty.

BPA faces several other uncertainties over the next few years, which may affect market risk. The deregulated electricity industry market has brought significant volatility to market prices and may continue to do so. National and state regulatory changes have been leading to further restructuring in the industry through ongoing discussions of a regional transmission organization. Price caps have been modified during the past fiscal year. Resource development has been in a state of flux. All of these factors contribute to the environment of market risk in which BPA continues to operate.

Financial Statements

Statements of Revenues and Expenses

Federal Columbia River Power System
For the years ended Sept. 30 — Thousands of dollars

	2002	2001	2000
Operating Revenues			
Sales	$ 3,407,404	$ 3,563,182	$ 2,903,735
SFAS 133 mark-to-market	38,354	47,877	—
Miscellaneous Revenues	49,571	66,902	103,251
U.S. Treasury Credits for Fish	38,400	600,708	60,000
Total operating revenues	3,533,729	4,278,669	3,066,986
Operating Expenses			
Operations and maintenance	1,319,707	1,023,180	977,439
Purchased power	1,286,867	2,296,076	633,142
Nonfederal projects (Note 4)	230,175	473,100	560,836
Federal projects depreciation	335,205	323,314	319,942
Total operating expenses	3,171,954	4,115,670	2,491,359
Net operating revenues	361,775	162,999	575,627
Interest Expense			
Interest on federal investment:			
Appropriated funds (Note 3)	258,195	248,429	248,352
Long-term debt (Note 2)	151,997	129,159	115,052
Allowance for funds used during construction	(57,892)	(45,679)	(28,754)
Net interest expense	352,300	331,909	334,650
Net revenues (expenses) before cumulative effect of SFAS 133	9,475	(168,910)	240,977
Cumulative effect of SFAS 133	—	(168,491)	—
Net Revenues (Expenses)	9,475	(337,401)	240,977
Accumulated net (expenses) revenues, Oct. 1	(221,151)	132,810	(108,167)
Irrigation Assistance	—	(16,560)	—
Accumulated net (expenses) revenues, Sept. 30	**$ (211,676)**	**$ (221,151)**	**$ 132,810**

The accompanying notes are an integral part of these statements.

Balance Sheets

Federal Columbia River Power System
As of Sept. 30 — Thousands of dollars

Assets

	2002	2001
Utility Plant (Notes 1 and 3)		
Completed plant	$ 11,488,047	$ 11,249,158
Accumulated depreciation	(4,052,117)	(3,817,309)
	7,435,930	7,431,849
Construction work in progress	1,200,179	913,670
Net utility plant	8,636,109	8,345,519
Nonfederal Projects (Note 4)		
Conservation	47,733	50,189
Hydro	167,080	170,730
Nuclear	2,127,907	2,116,473
Terminated hydro facilities	29,555	30,245
Terminated nuclear facilities	3,829,269	3,804,312
Total nonfederal projects	6,201,544	6,171,949
Trojan Decommissioning Cost (Note 5)	73,861	69,221
Conservation, net of accumulated amortization of $831,631 in 2002 and $769,221 in 2001 (Notes 1 and 2)	409,571	444,021
Fish and Wildlife, net of accumulated amortization of $129,207 in 2002 and $110,954 in 2001 (Notes 1 and 2)	134,204	146,354
Current Assets		
Cash	235,409	667,306
Accounts receivable	299,040	387,805
Materials and supplies, at average cost	85,107	85,222
Prepaid expenses	285,696	187,149
Total current assets	905,252	1,327,482
Other Assets	151,458	265,984
	$ 16,511,999	**$ 16,770,530**

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2002	2001
Capitalization and Long-Term Liabilities		
Accumulated net expenses (Note 1)	$ (211,676)	$ (221,151)
Federal appropriations (Note 3)	4,595,915	4,647,017
Capitalization adjustment (Note 3)	2,192,400	2,259,756
Long-term debt (Note 2)	2,563,141	2,582,542
Nonfederal projects debt (Note 4)	5,958,538	5,954,490
Trojan decommissioning reserve (Note 5)	63,861	57,221
Total capitalization and long-term liabilities	15,162,179	15,279,875
Commitments and Contingencies (Notes 5 and 6)		
Current Liabilities		
Current portion of federal appropriations	46,687	23,913
Current portion of long-term debt	207,300	106,000
Current portion of nonfederal projects debt	243,006	217,459
Current portion of Trojan decommissioning reserve	10,000	12,000
Accounts payable and other current liabilities	343,425	510,957
Total current liabilities	850,418	870,329
Deferred Credits (Note 1)	499,402	620,326
	$16,511,999	**$16,770,530**

Statements of Changes in Capitalization and Long-Term Liabilities

Federal Columbia River Power System
Including current portions — Thousands of dollars

	Accumulated Net Revenues (Expenses)	Federal Appropriations	Long-Term Debt	Nonfederal Project Debt	Other	Total
Balance at Sept. 30, 2000	**$ 132,810**	**$4,566,011**	**$2,513,200**	**$6,408,865**	**$2,406,847**	**$16,027,733**
Increase in federal appropriations:						
Construction	—	230,388	—	—	—	230,388
Repayment of federal appropriations:						
Construction	—	(125,469)	—	—	—	(125,469)
Capitalization adjustment amortization	—	—	—	—	(68,784)	(68,784)
Irrigation Assistance	(16,560)	—	—	—	—	(16,560)
Increase in long-term debt	—	—	260,000	—	—	260,000
Repayment of long-term debt	—	—	(84,658)	—	—	(84,658)
Net decrease in nonfederal projects debt	—	—	—	(60,658)	—	(60,658)
Repayment of nonfederal projects debt	—	—	—	(176,258)	—	(176,258)
Trojan decommissioning reserve	—	—	—	—	(9,086)	(9,086)
Net expenses	(337,401)	—	—	—	—	(337,401)
Balance at Sept. 30, 2001	**$ (221,151)**	**$4,670,930**	**$2,688,542**	**$6,171,949**	**$2,328,977**	**$15,639,247**
Increase in federal appropriations:						
Construction	—	168,583	—	—	—	168,583
Repayment of federal appropriations:						
Construction	—	(196,911)	—	—	—	(196,911)
Capitalization adjustment amortization	—	—	—	—	(67,356)	(67,356)
Increase in long-term debt	—	—	390,000	—	—	390,000
Repayment of long-term debt	—	—	(308,101)	—	—	(308,101)
Net increase in nonfederal projects debt	—	—	—	258,775	—	258,775
Repayment of nonfederal projects debt	—	—	—	(229,180)	—	(229,180)
Trojan decommissioning reserve	—	—	—	—	4,640	4,640
Net revenues	9,475	—	—	—	—	9,475
Balance at Sept. 30, 2002	**$ (211,676)**	**$4,642,602**	**$2,770,441**	**$6,201,544**	**$2,266,261**	**$15,669,172**

The accompanying notes are an integral part of these statements.

Statements of Cash Flows

Federal Columbia River Power System
For the years ended Sept. 30 — Thousands of dollars

	2002	2001	2000
Cash from Operating Activities			
Net revenues (expenses)	$ 9,475	$ (337,401)	$ 240,977
Expenses (income) not requiring cash:			
Depreciation	254,332	247,247	242,673
Amortization of conservation and fish and wildlife	78,047	76,067	77,269
Amortization of nonfederal projects	229,180	176,258	323,619
Amortization of capitalization adjustment	(67,356)	(68,784)	(67,474)
AFUDC	(57,892)	(45,679)	(28,754)
(Increase) decrease in:			
Accounts receivable	88,765	(31,283)	(155,444)
Materials and supplies	115	(20,930)	6,785
Prepaid expenses	(98,547)	(101,254)	(3,200)
Increase (decrease) in:			
Accounts payable	(167,532)	138,687	100,699
Other	(6,399)	114,060	8,437
Cash provided by operating activities	262,188	146,988	745,587
Cash from Investment Activities			
Investment in:			
Utility plant	(487,030)	(399,220)	(310,165)
Conservation	(25,344)	141	—
Fish and wildlife	(6,102)	(16,493)	(13,898)
Cash used for investment activities	(518,476)	(415,572)	(324,063)
Cash from Borrowing and Appropriations			
Increase in federal constructions appropriations	168,583	230,388	129,953
Repayment of federal construction appropriations	(196,911)	(125,469)	(62,425)
Irrigation assistance	—	(16,560)	—
Increase in long-term debt	390,000	260,000	294,300
Repayment of long-term debt	(308,101)	(84,658)	(227,500)
Refinance of long-term debt	—	—	(68,800)
Payment of nonfederal debt	(229,180)	(176,258)	(323,619)
Cash (used for) provided by borrowing and appropriations	(175,609)	87,443	(258,091)
(Decrease) increase in cash	(431,897)	(181,141)	163,433
Beginning cash balance	667,306	848,447	685,014
Ending cash balance	**$ 235,409**	**$ 667,306**	**$ 848,447**

The accompanying notes are an integral part of these statements.

Notes to Financial Statements

1. Summary of General Accounting Policies

Principles of Combination

The Federal Columbia River Power System (FCRPS) includes the accounts of the Bonneville Power Administration (BPA), which purchases, transmits and markets power, and the accounts of generating facilities of the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) for which BPA is the power marketing agency. Each entity is separately managed and financed, but the facilities are operated as an integrated power system with the financial results combined as the FCRPS. The costs of multipurpose Corps and Reclamation projects are assigned to specific purposes through a cost allocation process. Only the portion of total project costs allocated to power is included in these statements.

FCRPS accounts are maintained in accordance with generally accepted accounting principles and the uniform system of accounts prescribed for electric utilities by the Federal Energy Regulatory Commission (FERC). FCRPS accounting policies also reflect specific legislation and executive directives issued by U.S. government departments. (BPA is a unit of the Department of Energy; Reclamation is part of the Department of the Interior; and the Corps is part of the Department of Defense.) FCRPS properties and income are tax-exempt. All material intercompany accounts and transactions have been eliminated from the combined financial statements.

Management Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Standards of Ethical Conduct

As part of the United States federal government, employees of the FCRPS are bound by Standards of Ethical Conduct for Employees of the Executive Branch. The Standards contains 14 general principles that address topics such as placing ethical principles above private gain, not engaging in conflicts of interest, not using public office for private gain, and complying with all applicable governmental rules and regulations. The Standards document spells out these principles in great detail and includes examples of how to respond in situations where ethical dilemmas arise. All employees of the FCRPS, including executives, are required to receive federal ethics training and sign a document stating they understand the Standards of Ethical Conduct on an annual basis.

Reclassifications

Certain reclassifications were made to the 2000 and 2001 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2002. Such reclassifications had no effect on previously reported results of operations and cash flows.

Regulatory Authority

BPA's rates are established in accordance with several statutory directives. Rates proposed by BPA are subjected to an extensive formal review process, after which they are established by BPA and reviewed by FERC. FERC's review is limited to three standards set out in the the Pacific Northwest Electric Power Planning and Conservation Act (Act), 16 U.S.C. 839, and a standard set by the National Energy Policy Act of 1992. FERC reviews BPA's rates for all firm power, for nonfirm energy sold within the region, and for transmission service. Statutory standards include a requirement that these rates be sufficient to assure repayment of the federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs.

After final FERC approval, BPA's rates may be reviewed by the United States Court of Appeals for the Ninth Circuit. Action seeking such review must be filed within 90 days of the final FERC decision. FERC and the court of appeals may either confirm or reject a rate proposed by BPA. It is the opinion of BPA's general counsel that, if a rate were rejected, it would be remanded to BPA for reformulation. By contract, BPA has agreed that rates for the sale of power pursuant to its present contracts may not be revised until the current rate period expires on Sept. 30, 2006, except for certain rate cost recovery adjustment clauses (CRACs). The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. There are three sets of conditions in which rate increases under the CRACs may trigger. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA incurs costs for meeting or reducing loads that were not included in the rate case. The second is the Financial-Based CRAC (FB CRAC), which triggers if the generation function's forecasted level of accumulated net revenues is below a pre-determined threshold. The third is the Safety-Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has missed or reasonably expects to miss a payment to the Treasury or another creditor. Of these certain rate adjustment clauses, some are calculated on forward-looking market conditions and adjustments are made after-the-fact when actual conditions are known. These adjustments result in an additional charge or rebate due customers for any excess or shortfall of amounts initially charged to them.

On Oct. 1, 2001, implementation of the LB CRAC caused BPA's rates to increase approximately 46 percent for the first half of fiscal 2002 compared to base rates. The LB CRAC percentage changes every 6 months. The increase was 41 percent for the second half of fiscal 2002. The LB CRAC percentage will be revised for the six-month periods beginning Oct. 1, 2002 and April 1, 2003.

At Sept. 30, 2002, BPA has recognized a liability of $5.8 million for the LB CRAC period ended March 31, 2002, and a receivable of $2.3 million for the LB CRAC ended Sept. 30, 2002. The August forecast of the generation function's accumulated net revenues triggered the FB CRAC, and resulted in a one-year rate increase beginning Oct. 1, 2002, of approximately 11 percent for most of the requirement rates on top of the revised levels of the LB CRAC. SN CRAC did not trigger in fiscal 2002.

In addition to the CRACs, BPA established contracts and rates for a "Slice of the System Product." The basic premise of the product is that a purchaser pays a fixed percent of BPA's power costs in exchange for a fixed percent of generation and capabilities. Settlement of any over or under collection is in the subsequent year. For the fiscal 2002 settlement, BPA has recognized a receivable of $49 million to be received in fiscal 2003.

FERC granted final approval for proposed Power and Transmission rates on April 4, 1997, for fiscal years 1997 through 2001 (75 FERC 62,010 (1997)).

BPA submitted a separate Transmission and Ancillary Services Rate Filing in 2000 for fiscal years 2002 through 2003, and a Power Rate Filing in 2001 for fiscal years 2002 through 2006. FERC granted final approval of BPA's Transmission and Ancillary Services rates on May 7, 2001, for fiscal years 2002 through 2003, 62 FERC 62,094 (2001). On June 29, 2001, FERC granted final approval for the acceleration of the Ancillary Services and Control Area Services Rate (ACS-02) for Generation Imbalance Service (GIS), 95 FERC 62,286 (2001); and on October 11, 2001, FERC granted final approval for corrections of the ACS-02 rate, 97 FERC 62,020 (2001). FERC granted interim approval for proposed Power rates on Sept. 28, 2001, for fiscal years 2002 through 2006, 96 FERC 61,360 (2001).

Because of the regulatory environment in which BPA establishes rates, certain costs may be deferred and expensed in future periods under Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation.

SFAS 71 Assets

As of Sept. 30 — Thousands of dollars

	2002	2001
Nonfederal projects		
Conservation	$ 47,733	$ 50,189
Terminated nuclear facilities	3,829,269	3,804,312
Terminated hydro facilities	29,555	30,245
Trojan decommissioning cost	73,861	69,221
Conservation	409,571	444,021
Fish and wildlife	134,204	146,354
Additional retirement contributions	36,800	68,100
Total	**$ 4,560,993**	**$ 4,612,442**

In order to defer incurred costs under SFAS 71, a regulated entity must have the statutory authority to establish rates that recover all costs and rates so established must be charged to and collected from customers. Due to increasing competitive pressures, BPA may be required to seek alternative solutions in the future to avoid raising rates to a level that is no longer competitive. If BPA's rates should become market-based, SFAS 71 would no longer be applicable, and any costs deferred under that standard would be expensed in the Statement of Revenues and Expenses.

The SFAS 71 assets of $4.6 billion, shown in the table on page 31, reflect a decrease of $51 million from the prior year. Amortization of these costs aggregating $293 million in fiscal 2002, $259 million in 2001 and $276 million in fiscal 2000 is reflected in the Statements of Revenues and Expenses.

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues of $93 million at Sept. 30, 2002, and $6 million at Sept. 30, 2001. Estimated unbilled revenues are included in accounts receivable in the accompanying Balance Sheets. BPA operates as two segments: The Power Business Line and the Transmission Business Line. The table in Note 7 reflects the revenues and expenses attributable to each business line. Because BPA is a U.S. government power marketing agency, net revenues over time are committed to repayment of the U.S. government investment in the FCRPS and the payment of certain irrigation costs as discussed in Note 5.

Utility Plant

Utility plant is stated at original cost. Cost includes direct labor and materials; payments to contractors; indirect charges for engineering, supervision and similar overhead items; and an allowance for funds used during construction. The costs of additions, major replacements and betterments are capitalized. Repairs and minor replacements are charged to operating expense. In accordance with FERC requirements the cost of utility plant retired, together with removal costs less salvage, is charged to accumulated depreciation when it is removed from service.

Allowance for Funds Used During Construction

The allowance for funds used during construction (AFUDC) constitutes interest on the funds used for utility plant under construction. AFUDC is capitalized as part of the cost of utility plant and results in a non-cash reduction of interest expense. While cash is not realized currently from this allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from higher plant in-service and higher depreciation expenses. AFUDC is based on the monthly construction work in progress (CWIP) balance. A portion of CWIP as stated on the balance sheets represents study and investigation costs to which AFUDC is not attributed.

AFUDC capitalization rates are stipulated in the congressional acts authorizing construction for certain generating projects (2.5 percent to 6.5 percent in 2002, 2.5 percent to 6.6 percent in 2001 and 2.5 percent to 6.7 percent in 2000). Capitalization rates for other construction approximate the cost of borrowing from the U.S. Treasury (6.0 percent in 2002, 6.5 percent in 2001 and 6.6 percent in 2000).

Depreciation and Amortization

Depreciation of original cost and estimated cost to retire utility plant is computed on the straight-line method based on estimated service lives of the various classes of property, which average 40 years for transmission plant and 75 years for generation plant. Amortization of capitalized conservation and fish and wildlife costs is computed on the straight-line method based on estimated service lives, which are 10 to 20 years for conservation and 15 years for fish and wildlife.

Fish Credits

The Act obligated the BPA administrator to make expenditures for fish and wildlife protection, mitigation, and enhancement for both power and non-power purposes, on a reimbursement basis. It also specified that consumers of electric power, through their rates for power services "shall bear the costs of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only." Section 4(h)(10)(C) of the Act was designed to ensure that the costs of mitigating these impacts are properly accounted for among the various purposes of the hydroelectric projects.

BPA, the U.S. Treasury and the Office of Management and Budget agreed to a crediting mechanism against Bonneville's Treasury payments to reimburse BPA for expenditures made on behalf of mitigation for non-power purposes. Under the agreed-upon crediting mechanism, BPA reduces its cash payments to Treasury by an amount equal to the mitigation measures funded on behalf of the non-power purposes. The credits are used to recoup the amount owed to BPA by the other project purposes. Bonneville has taken this credit since 1995, in amounts that, with the exception of FY 2001, ranged between $26 million and $60 million.

IOU Subscription Settlement Agreements and Residential Exchange

As provided for in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. 839, Section 5(c), BPA entered into residential exchange contracts with most of its electric utility customers. These contracts resulted in payments to the utilities if a utility's average system cost exceeded BPA's priority firm power rate.

Subsequently, contract termination agreements were signed by all actively exchanging Pacific Northwest utilities except Northwestern Energy (formerly the Montana Power Co., which had not been receiving benefits). BPA made payments to settle the utilities' and BPA's rights and obligations under the residential exchange program through June 30, 2001, and in some cases, through June 30, 2011.

In Oct. 2000, BPA's investor-owned utility (IOU) customers signed subscription settlement agreements determining exchange benefits for the period from July 1, 2001 through Sept. 30, 2011. These agreements provide for both sales of power and payments to the IOUs. The table below summarizes future IOU benefits as of Sept. 30, 2002.

Exchange Benefits

Thousands of dollars

IOU Benefits	
2003	$ 359,850
2004	359,850
2005	359,850
2006	359,850
Total	**$ 1,439,400**

Benefits beyond the current rate case period cannot currently be quantified.

Retirement Benefits

FCRPS employees belong to either the Civil Service Retirement System (CSRS) or the Federal Employees' Retirement System (FERS). FCRPS and its employees contribute to the systems. Based on the statutory contribution rates, retirement benefit expense under CSRS is equivalent to 7 percent of eligible employee compensation and under FERS is variable based upon options chosen by the participant but does not exceed 24.2 percent of eligible employee compensation. Retirement benefits are payable by the U.S. Treasury and not by the FCRPS.

Beginning in fiscal 1998, and for the remainder of the rate period ended in 2001, FCRPS agreed to contribute additional amounts as a result of an underfunded status of the CSRS. These amounts have been calculated based on an estimate of FCRPS employees who participate in the plan as well as an estimate of FCRPS' share of the underfunded status. These contributions are projected over a period of years as shown in the table. The payments, when made, will be directly to the U.S. Treasury.

BPA paid approximately $55.2 million and $8.0 million to the U.S. Treasury during fiscal 2002 and 2001, respectively. These amounts were recorded as expense when paid. BPA has accrued $36.8 million as of Sept. 30, 2002, which represents the additional deferred contribution for fiscal 1998, 1999, 2000, 2001 and 2002. This amount has been recorded as an SFAS 71 asset on the balance sheet for recovery of the costs through rates in the period beginning Oct. 1, 2001. The related liability is included in other current liabilities and deferred credits in the accompanying Balance Sheet. At Sept. 30, 2002, BPA has scheduled additional payments totaling $136.8 million as follows.

Scheduled Additional CSRS Contributions

Millions of dollars

Scheduled Contributions	
2003	$ 35.1
2004	30.9
2005	26.5
2006	23.2
2007	21.1
Total	**$ 136.8**

BPA expects to recognize these amounts as expense in the years in which they are specifically recovered through rates.

Cash

For purposes of reporting cash flows, cash includes cash in the BPA fund and unexpended appropriations of Reclamation and the Corps. Cash paid for interest was $484 million in 2002, $464 million in 2001 and $403 million in 2000.

Non-cash transactions include changes in nonfederal projects and nonfederal projects' debt (other than amortization of nonfederal projects and payment of nonfederal projects' debt) of $259 million in 2002, $61 million in 2001 and $40 million in 2000.

Concentrations of Credit Risks

General Credit Risk

Financial instruments, which potentially subject the FCRPS to concentrations of credit risk, consist of available-for-sale investments held by Energy Northwest and BPA accounts receivable. Energy Northwest invests exclusively in U.S. Government securities and agencies. BPA's accounts receivable are concentrated with a diverse group of customers and counterparties who have purchased capacity, energy, or other products and services. These customers are generally large and stable and do not represent a significant concentration of credit risk.

BPA mitigates credit risk by insisting that counterparties and marketers are significant industry companies that are considered financially strong. BPA performs an initial financial review of new counterparties and establishes credit limits based on the results of that review. Reviews and credit limits are updated regularly to reflect the current financial conditions of the company.

In conjunction with the financial reviews, BPA often obtains credit support in the form of parental guarantees and letters of credit to support established credit limits. BPA also utilizes netting agreements to mitigate the credit risk of financial instruments.

Bonneville has open purchase and sales contracts with a diverse group of customers including Enron Power Marketing Inc. (Enron). Enron and its parent company, Enron Corp. filed for bankruptcy protection in December 2001. Due to the nature of the contracts with Enron, management does not consider it necessary to record a provision for loss or for uncollectible amounts as of Sept. 30, 2002, relating to Enron transactions.

Credit Risk from California

California power markets have been in turmoil for several years, having experienced historically high power prices and volatility. Defaults by Pacific Gas & Electric (which filed for bankruptcy protection in April 2001) and Southern California Edison (which has established a creditor payment plan) in payments for energy and transmission to the California Independent System Operator (Cal-ISO) have resulted in concerns by energy suppliers that the Cal-ISO may not be a creditworthy supplier. In addition, the California Power Exchange (Cal-PX) has substantial outstanding payment obligations due from the California investor-owned-utilities for day-ahead power exchanges. The Cal-PX filed for bankruptcy protection in March 2001.

Bonneville entered into certain power sales through the Cal-PX for which Bonneville has not yet been paid. In addition Bonneville sold power and related services to the Cal-ISO for which Bonneville has not yet been paid in full. Bonneville also has a long-term seasonal power exchange agreement with Southern California Edison. Based on management's current evaluation, the amount of ultimate or potential losses is not determinable at this time. However, Bonneville has recorded provisions for uncollectible receivable and potential refund amounts, which in management's best estimate are sufficient to cover potential exposure. Nonetheless, Bonneville is continuing to pursue collection of all amounts due in bankruptcy and other proceedings.

Deferred Credits

Deferred credits consist of $127 million paid to BPA from participants under the 3rd AC intertie capacity agreement, $126.4 million in advances from customers for projects which BPA is constructing on their behalf, $95.2 million in load diversification fees and other settlement payments for long-term agreements paid to BPA from various customers, $82.3 million current fair market value of purchased and written options and certain trading physical forward sales and purchases, $23.7 million leasing fees for fiber optic cable, $23.4 million in deferred CSRS, $21.1 million in unearned option premium revenue, and $.3 million in other miscellaneous long-term liabilities.

Deferred 3rd AC intertie capacity payments are recognized as revenue over the estimated 37-year life of the related assets. Advances on projects BPA constructs for customers are either applied against the expenditure during the construction of the assets if the customer retains title to the assets, or if BPA retains title, are recorded to revenue over the related useful lives of the assets. Diversification fees are payments by customers to BPA in consideration for a reduction in their contractually obligated power purchases from BPA. Deferred diversification fees and other settlement payments for long-term agreements are recognized as revenue over the original contract terms (diversification fee contracts generally correspond to the rate period ended Sept. 30, 2001, while other settlement agreements extend over varying periods through 2019). Leasing fees for fiber optic cable are recognized over the lease terms extending as far as 2020. The current portion of deferred credits to be recorded as revenue in fiscal 2002 is included in accounts payable and other current liabilities in the Balance Sheet.

Hedging and Derivative Instrument Activities

BPA's hedging policy (Policy) allows the use of financial instruments such as commodity futures, options and swaps to hedge the price and revenue risk associated with electricity sales and purchases and to hedge risks associated with new product development. The Policy does not authorize the use of financial instruments for non-hedging purposes, unless such use is expressly authorized under specific provisions included in the Policy. BPA had no material hedging or financial instruments outstanding as of Sept. 30, 2002.

Historically, BPA has used financial instruments in the form of Over-the-Counter (OTC) electricity swap agreements and options and Exchange traded futures contracts to hedge anticipated production and marketing of hydroelectric energy. Under swap agreements, BPA makes or receives payments based on the differential between a specified fixed price and an index reference price of power. Under futures contracts, BPA either sells or buys Exchange traded futures contracts to hedge anticipated future electricity sales and purchases. There were no open or outstanding OTC electricity swap agreements or Exchange traded electricity futures and options at Sept. 30, 2002.

As of and for the years ended Sept. 30, 2002 and 2001, both the deferred and the realized gains and losses resulting from these transactions were not material to the consolidated FCRPS financial statements.

Written Options

BPA sells put and call options for the purchase and sale of electricity at certain points in the future. BPA's intention is to fulfill all call options exercised with its estimated surplus generating capability at the future dates and to take delivery of power as a result of written put options if exercised. The megawatt-hour quantities that BPA sells and the premiums that BPA collects for the sales of these options are priced on market based information and a mathematical model developed by BPA. This model makes certain assumptions based on historical and other statistical data. Actual future results could vary from estimates resulting in the requirement that BPA fulfill these sales obligations with power purchases at a cost in excess of the prices stated in the contracts. In addition, BPA may be required to buy power at strike prices above market prices as a result of its written put option obligations.

As of Sept. 30, 2002, there were no written call options outstanding compared to 409,600 megawatt-hours outstanding with an average strike price of $130.25 per megawatt-hour as of Sept. 30, 2001. As of Sept. 30, 2002, written put options totaling 3,507,600 megawatt-hours were outstanding with an average strike price of $42.25 per megawatt-hour compared to 10,112,003 megawatt-hours outstanding as of Sept. 30, 2001. These options expire at various times through Dec. 2005. BPA records written options on a mark-to-market basis and includes gains and losses in operating revenues in the Statement of Revenues and Expenses.

Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheet as of Sept. 30, 2002 and 2001. The carrying value reflected in the Balance Sheet approximates fair value for the FCRPS's financial assets and current liabilities. The fair values of long-term liabilities are discussed in the respective footnotes.

Adoption of Statement 133

BPA adopted SFAS 133, "Accounting for Derivative Instrument and Hedging Activities," as amended, on Oct. 1, 2000. SFAS 133 requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. SFAS 133 requires that as of the date of initial adoption, the difference between the fair market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivatives be reported in net income or other comprehensive income, as appropriate.

It is BPA's policy to document and apply as appropriate the normal purchase and normal sales exception under SFAS 133, as amended by SFAS 138 paragraph 4 (a), and Derivatives Implementation Group issue C15: "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." For all other non-hedging related derivative transactions BPA applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. Bonneville may also elect to use special hedge accounting provisions allowed under SFAS 133 for transactions that meet certain documentation requirements. As of Sept. 30, 2002, BPA had no outstanding transactions accounted for under the special hedge accounting provisions.

On the date of adoption (Oct. 1, 2000), in accordance with the transition provisions of SFAS 133, BPA recorded a cumulative-effect adjustment of $(168) million in net revenue (expense) to recognize the difference between the carrying values and fair values of derivatives not designated as hedging instruments. The adjustment consisted mainly of transactions known as bookouts that the FASB initially determined should be fair valued in net revenue (expense). While authoritative guidance in this area continued to emerge during fiscal year 2001, BPA management elected to apply the most current guidance available.

On June 29, 2001, the FASB issued definitive guidance on Derivatives Implementation Group issue C15: "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." Issue C15 provided additional guidance on the classification and application of SFAS 133 relating to purchases and sales of electricity utilizing forward contracts and options including bookout transactions. This guidance became effective as of July 1, 2001. Purchases and sales of forward electricity and option contracts that require physical delivery and which are expected to be used or sold by the reporting entity in the normal course of business are generally considered "normal purchases and normal sales" under SFAS 133. These transactions are outside of the scope of SFAS 133 and therefore are not required to be marked to fair value in the financial statements. BPA elected this treatment of bookout transactions effective as of Sept. 30, 2001.

For the fiscal year ended Sept. 30, 2002 Statement of Revenues and Expenses BPA recorded $38.4 million of gains from SFAS 133 fair value application related to certain option and physical forward sales and purchase transactions. This included a $61.3 million gain for open option contracts and a $(22.9) million loss for certain physical forward sales and purchase transactions.

Recent Accounting Pronouncements

In June 2001, FASB issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets." Evaluations of SFAS 141 and 142 have been completed and we have determined there is no current effect on FCRPS financial statements.

In June 2001, FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. BPA is continuing to determine the impact, if any, of SFAS 143 on BPA's financial statements. If applicable, SFAS 143 will be effective for BPA starting with the fiscal year ending Sept. 30, 2003.

In August 2001, FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. An evaluation of SFAS 144 has been completed and we have determined there is no current effect on FCRPS financial statements.

In April 2002, FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," and in June 2002, FASB issued SFAS No. 146 "Accounting for Costs Associated with Exit of Disposal Activities." Evaluations of SFAS 145 and 146 have been completed and we have determined there is no current effect on FCRPS financial statements.

2. Long-Term Debt

To finance its capital programs, BPA is authorized by the Federal Columbia River Transmission System Act to issue to the U.S. Treasury up to $3.75 billion of interest-bearing debt with terms and conditions comparable to debt issued by U.S. government corporations. A portion ($1.25 billion) of the $3.75 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2002, $350 million of this reserved amount and $2,420 million of other borrowings were outstanding. The average interest rate of BPA's borrowings from the U.S. Treasury exceeds the rate that could be obtained currently. As a result, the fair value of the BPA long-term debt, based upon discounting future cash flows using rates offered by the U.S. Treasury as of Sept. 30, 2002, for similar maturities exceeds carrying value by approximately $497 million, or 18 percent. The table below reflects the terms and amounts of long-term debt.

U.S. Treasury Bonds

Long-Term Debt (a) — Thousands of dollars

	First Call Date	Maturity Date	Interest Rate	Construction and Fish & Wildlife	Conservation	Cumulative Total
November 1999	none	2002	6.40%	$ 40,000		$ 40,000
January 1996	none	2003	5.90%	60,000		100,000
September 1999	none	2003	6.30%	20,000		120,000
April 2000 (b)	none	2003	6.85%	40,000		160,000
July 2000	none	2003	6.95%		$ 32,000	192,000
August 2000	none	2003	6.85%	15,300		207,300
January 1997	none	2004	6.80%	30,000		237,300
May 1999	none	2004	5.95%	26,200		263,500
September 1999 (b)	none	2004	6.40%	20,000		283,500
July 2000	none	2004	7.00%	50,000		333,500
June 2001 (b)	none	2004	4.75%	50,000		383,500
May 1997	none	2005	6.90%	80,000		463,500
January 2000	none	2005	7.15%	53,500		517,000
September 2000 (b)	none	2005	6.70%	20,000		537,000
January 2001	none	2005	5.65%	20,000		557,000
January 2001	none	2005	5.65%	25,000		582,000
March 2002	none	2005	4.60%	110,000		692,000
March 2002 (b)	none	2005	4.60%	30,000		722,000
June 2002	none	2005	3.75%	60,000		782,000
June 2002	none	2005	3.75%		40,000	822,000
August 1996	none	2006	7.05%	70,000		892,000
September 2000	none	2006	6.75%	40,000		932,000
September 2002	none	2006	3.05%	100,000		1,032,000
September 2002	none	2006	3.05%	30,000		1,062,000
September 2002 (b)	none	2006	3.05%	20,000		1,082,000
August 1997	none	2007	6.65%	111,300		1,193,300
April 1998	none	2008	6.00%	75,300		1,268,600
April 1998 (b)	none	2008	6.00%	25,000		1,293,600
August 1998	none	2008	5.75%	40,000		1,333,600
September 1998	none	2008	5.30%		104,300	1,437,900
July 1989	none	2009	8.55%		40,000	1,477,900
May 1998	none	2009	6.00%	72,700		1,550,600
May 1998	none	2009	6.00%		37,700	1,588,300
January 2001	none	2010	6.05%	30,000		1,618,300
January 2001	none	2010	6.05%	60,000		1,678,300
January 1996	2001	2011	6.70%		30,000	1,708,300
November 1996	2001	2011	6.95%	40,000		1,748,300
May 1998	none	2011	6.20%	40,000		1,788,300
June 2001	none	2011	5.95%	25,000		1,813,300
August 2001	none	2011	5.75%	50,000		1,863,300
January 1998	none	2013	6.10%	60,000		1,923,300
September 1998	none	2013	5.60%		52,800	1,976,100
January 1994	1999	2014	6.75%		13,265	1,989,365
February 1999	none	2014	5.90%	60,000		2,049,365
July 1995	2000	2025	7.70%	34,976		2,084,341
April 1998	2008	2028	6.65%	50,000		2,134,341
August 1998	none	2028	5.85%	106,500		2,240,841
August 1998	none	2028	5.85%	112,300		2,353,141
May 1998	2008	2032	6.70%	98,900		2,452,041
August 1993	1998	2033	6.95%	110,000		2,562,041
October 1993	1998	2033	6.85%	108,400		2,670,441
October 1993	1998	2033	6.85%	50,000		2,720,441
January 1994	1999	2034	7.05%	50,000		2,770,441
				$ 2,420,376	**$ 350,065**	**$ 2,770,441**
Less current portion						(207,300)
						$ 2,563,141

(a) The weighted average interest rate was 6 percent on outstanding long-term debt as of Sept. 30, 2002. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

(b) Corps/Reclamation direct funding.

3. Federal Appropriations

The BPA Appropriations Refinancing Act (Refinancing Act), 16 U.S.C. 8381, required that the outstanding balance of the FCRPS federal appropriations, which Bonneville is obligated to set rates to recover, be reset and assigned prevailing market rates of interest as of Sept. 30, 1996. The resulting principal amount of appropriations was determined to be equal to the present value of the principal and interest that would have been paid to Treasury in the absence of the Refinancing Act, plus $100 million. The $100 million was capitalized as part of the appropriations balance and was included pro rata in the new principal of the individual appropriated repayment obligations.

The amount of appropriations refinanced was $6.6 billion. After refinancing, the appropriations outstanding were $4.1 billion. The difference between the appropriated debt before and after the refinancing was recorded as a capitalization adjustment. This adjustment is being amortized over the remaining period of repayment so that total FCRPS net interest expense is equal to what it would have been in the absence of the Refinancing Act.

Amortization of the capitalization adjustment was $67.4 million for fiscal 2002 and $68.8 million for 2001, and $67.5 million for 2000. The weighted-average interest rate was 7.0 percent in 2002, and 6.9 percent in 2001 and 7.1 percent in 2000.

Construction and replacement of Corps and Reclamation generating facilities have historically been financed through annual federal appropriations. Annual appropriations were also made for their operation and maintenance costs, although these are normally repaid by BPA to the U.S. Treasury by the end of each fiscal year. As a result of the National Energy Policy Act of 1992 BPA has begun directly funding operation and maintenance expenses and capital efficiency and reliability improvements for Corps and Reclamation generating facilities.

Federal Generation and Transmission appropriations are repaid to the U.S. Treasury within the weighted average service lives of the associated investments (maximum 50 years) from the time each facility is placed in service.

If, in any given year, revenues are not sufficient to cover all cash needs, including interest, any deficiency becomes an unpaid annual expense. Interest is accrued on the unpaid annual expense until paid. This interest must be paid from subsequent years' revenues before any repayment of federal appropriations can be made.

The table below shows the term repayments on the remaining federal appropriations as of Sept. 30, 2002.

Federal Appropriations

Thousands of dollars

Term Repayments	
2003	$ 46,687
2004	73,484
2005	110,989
2006	68,939
2007	33,694
2008+	4,308,809
Total	**$ 4,642,602**

Includes payments on historic replacements but excludes planned future replacements and irrigation assistance.

4. Nonfederal Projects

BPA has acquired all or part of the generating capability of five nuclear power plants. The contracts to acquire the generating capability of the projects, referred to as "net-billing agreements," require BPA to pay all or part of the annual projects' budgets, including operating expense and debt service, including projects that are not completed and/or not operating. BPA has also acquired all of the output of the Cowlitz Falls and Wasco hydro projects. BPA has agreed to fund debt service on Eugene Water and Electric Board, Emerald, City of Tacoma and Conservation and Renewable Energy System bonds issued to finance conservation programs sponsored by BPA.

BPA recognizes expenses for these projects based upon total project cash funding requirements reflected in project budgets that are adopted by BPA and the projects' owners.

Operating expense of $175 million in fiscal 2002, $217 million in fiscal 2001 and $174 million in fiscal 2000 for the projects is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $230 million, $473 million and $561 million for fiscal 2002, 2001 and 2000, respectively, is reflected as nonfederal projects expense in the accompanying Statements of Revenues and Expenses.

The fair value of all Energy Northwest debt exceeds recorded value by $458 million or 7.6 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2002. All other nonfederal projects' debt approximates fair value as stated.

The following table summarizes future principal payments required for nonfederal projects as of Sept. 30, 2002.

Nonfederal Projects

Thousands of dollars

	Debt Repayments
2003	$ 243,006
2004	280,350
2005	239,048
2006	267,387
2007	291,865
2008+	4,879,888
Total	**$ 6,201,544**

5. Commitments and Contingencies

Irrigation Assistance

As directed by legislation, BPA is required to make cash distributions to the U.S. Treasury for original construction costs of certain Pacific Northwest irrigation projects that have been determined to be beyond the irrigators' ability to pay. These irrigation distributions do not specifically relate to power generation and are required only if doing so does not result in an increase to power rates. Accordingly, these distributions are not considered to be regular operating costs of the power program and are treated as distributions from accumulated net revenues (expenses) when paid. BPA paid irrigation assistance payments of $25 million and $17 million for 1997 and 2001 respectively. Future irrigation assistance payments ultimately could total $733 million and are scheduled over a maximum of 66 years. The May 2000 Interim Cost Reallocation Report prepared by Reclamation resulted in approximately $77 million of Columbia Basin Project costs being moved from irrigation to commercial power. BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects, which are beyond the ability of the 22 irrigation water users to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period.

The table below summarizes future irrigation assistance distributions as of Sept. 30, 2002.

Irrigation Assistance

Thousands of dollars

	Distributions
2003	$ —
2004	739
2005	—
2006	—
2007	—
2008+	732,195
Total	**$ 732,934**

Net-Billing Agreements

BPA has agreed with Energy Northwest that, in the event any participant shall be unable for any reason, or shall refuse, to pay to Energy Northwest any amount due from such participant under its net-billing agreement for which a net-billing credit or cash payment to such participant has been provided by BPA, BPA will be obligated to pay the unpaid amount in cash directly to Energy Northwest, unless payment of such unpaid amount is made in a timely manner pursuant to the net-billing agreements.

Nuclear Insurance

BPA is a member of the Nuclear Electric Insurance Limited (NEIL), a mutual insurance company established to provide insurance coverage for nuclear power plants. The types of insurance coverage purchased from NEIL by BPA include: 1) Primary Property and Decontamination Liability Insurance; 2) Decommissioning Liability and Excess Property Insurance; and 3) Business Interruption and/or Extra Expense Insurance.

Under each insurance policy BPA could be subject to an assessment in the event that a member-insured loss exceeds reinsurance and reserves held by NEIL. The maximum assessment for the Primary Property and Decontamination Insurance policy is $6.2 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $12 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.2 million.

As a separate requirement, BPA is liable under the Nuclear Regulatory Commission's indemnity for public liability coverage under the Price-Anderson Act. In the event of a nuclear accident resulting in public liability losses exceeding $200 million, BPA could be subject to a retrospective assessment of $88.1 million limited to an annual maximum of $10 million.

Decommissioning and Restoration Costs

In 1999 Energy Northwest successfully transferred assets and site restoration liability for WNP-3 to a consortium of local governments named the Satsop Redevelopment Project. In June 1999, Energy Northwest submitted a site restoration plan to the state of Washington's Energy Facility Site Evaluation Council (EFSEC) that complied with EFSEC's requirement to restore the WNP-1 and WNP-4 sites with minimal hazard to the public. This plan updated Energy Northwest's June 1995 plan. EFSEC's approval recognized that uncertainty still exists as to the exact details of the proposed plan; accordingly, EFSEC's conditional approval provided for additional reviews once the details of the plan are finalized. As part of submitting the restoration plan to EFSEC, Energy Northwest obtained outside estimates for site restoration of WNP-1 and WNP-4. BPA is required to fund site restoration for WNP-1. Funding for WNP-4 is uncertain. The cost of complete site restoration for WNP-1 and WNP-4 is estimated to be up to $60 million and $40 million respectively. BPA and Energy Northwest have been negotiating a reduced level of site restoration for WNP-1 as well as WNP-4 with EFSEC and the Department of Energy. A tentative conceptual solution involving a reduced level and delay in accomplishing restoration has been reached and is expected to be recommended for management approval in November. The estimated cost for the recommended level of site restoration at WNP-1 and WNP-4 is about $25 million and $23 million (2003 dollars) respectively. BPA believes the existing funds plus earnings will be adequate to cover all site restoration costs.

Decommissioning costs for Columbia Generating Station are charged to operations over the operating life of the project. An external decommissioning sinking fund for costs is being funded monthly for Columbia Generating Station. The sinking fund is expected to provide for decommissioning at the end of the project's operating life in accordance with Nuclear Regulatory Commission requirements. Sinking fund requirements for Columbia Generating Station are based on a NRC decommissioning cost estimate and assume a 40-year operating life.

The estimated decommissioning sum of expenditures for Columbia Generating Station is $340 million (1998 dollars). Payments to the sinking fund for the years ended Sept. 30, 2002, 2001 and 2000 were approximately $4 million per year. The sinking fund balance at Sept. 30, 2002, is $71 million.

In January 1993, the Portland General Electric board of directors formally notified BPA of its intent to terminate the operation of the Trojan plant. PGE's rate filing in December 1997 with the Oregon Public Utility Commission included an estimated total decommissioning liability of $424 million (in 1997 dollars). The current remaining estimate of $265 million is based on site-specific studies less actual expenditures to date. As of Sept. 30, 2002, BPA's 30-percent share of this estimated remaining liability is $74 million which has been recorded net of the decommissioning trust fund balance of $6 million in the accompanying Balance Sheet. The Trojan Decommissioning Plan calls for prompt decontamination with delayed demolition of non-radiological structures. Funding requirements will be greater in the early years of decommissioning and then will decrease significantly. These greater early funding requirements have altered the decommissioning trust fund contributions for 2000, 2001 and 2002. For the period 1995 through 2001, funding for the Trojan decommissioning trust fund is being applied directly to the decommissioning expenses. In 2002, the decommissioning trust fund was used to fund a portion of the 2002 Trojan decommissioning expenses. The decision to terminate the plant is not expected to result in the acceleration of debt-service payments. BPA will continue to recover its share of Trojan's costs through rates and decommissioning trust fund withdrawals. Decommissioning costs are included in operations and maintenance expense in the accompanying Statements of Revenues and Expenses.

Environmental Cleanup

From time to time, there are sites where BPA, Corps or Reclamation have been or may be identified as a potential responsible party. Costs associated with cleanup of those sites are not expected to be material to the FCRPS financial statements and would be recoverable through future rates.

Endangered Species Act

Actions related to the Endangered Species Act are included in BPA's costs and recovered through current rates.

Retirement Benefits

See Note 1 for discussion of additional civil service retirement system contributions scheduled for payment through 2007.

Purchase and Sales Commitments

BPA has entered into Subscription power sales for 3,000 average megawatts more power than the federal system produces on a firm-planning basis. These contracts run for as short as three and as long as 10 years from Oct. 1, 2001. Current rates recover the additional costs of the Subscription obligations through 2006. BPA's trading floor enters into sales commitments to sell expected surplus generating capabilities at future dates and purchase commitments to purchase power at future dates when BPA forecasts a shortage of generating capability and prices are favorable. Further, BPA enters into these contracts throughout the year to maximize its revenues on estimated surplus volumes. BPA records these sales and purchases in the month the underlying power is sold or purchased.

The table below summarizes future purchase power and sales commitments as of Sept. 30, 2002.

Purchase Power and Sales Commitments

Thousands of dollars

	. Purchase	. Sales
2003	$ 1,046,243	$ 2,122,146
2004	963,168	2,104,685
2005	996,904	2,104,686
2006	939,352	2,111,821
2007	98,823	100,445
2008+	362,570	275,043
Total	**$ 4,407,060**	**$ 8,818,826**

Augmentation commitments run through the rate case which ends in 2006.

6. Litigation

The FCRPS is party to various legal claims, actions and complaints, certain of which involve material amounts. Although the FCRPS is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management currently believes that disposition of these matters will not have a materially adverse effect on the FCRPS's financial position or results of operations.

7. Segments

In 1997 BPA opted to implement FERC's open-access rulemaking and standards of conduct. FERC requires that transmission activities are functionally separate from wholesale power merchant functions and that transmission is provided in a nondiscriminatory open-access manner.

The FCRPS's major operating segments are defined by the utility functions of generation and transmission. The Power Business Line represents the operations of the generation function, while the Transmission Business Line represents the operations of the transmission function. The business lines are not separate legal entities. Where applicable, "Corporate" represents items that are necessary to reconcile to the financial statements, which generally include shared activity and eliminations. Each FCRPS segment operates predominantly in one industry and geographic region: the generation and transmission of electric power in the Pacific Northwest.

The FCRPS centrally manages all interest expense activity. Since the Bonneville Power Administration has one fund with the U.S. Treasury, all cash and cash transactions are also centrally managed in the SFAS 131 Segment Reporting table. Unaffiliated revenues represent sales to external customers for each segment. Intersegment revenues are eliminated.

FCRPS management evaluates the performance of the business lines based on Net Operating Margin (NOM) and does not track the separate balance sheets or net revenues on a business line level. NOM represents revenues generated from operations less operating and maintenance expenses of the segment's revenue-generating assets. On a consolidated basis, this amount represents $994 million for fiscal 2002 ($3,534 million Operating Revenues less $38 million SFAS 133 mark-to-market, $38 million U.S. Treasury Credits for Fish, $1,177 million Operations and Maintenance and $1,287 million Purchased Power Expenses) as shown in the accompanying Statement of Revenues and Expenses.

Major Customers

During fiscal 2002, 2001 and 2000, no single customer represented 10 percent or more of the FCRPS's revenues.

SFAS 131 Segment Reporting

For the years ended Sept. 30 — Thousands of dollars

	Power	Transmission	Corporate	Total
2002				
Unaffiliated Revenues	$ 2,967,075	$ 566,654	$ —	$ 3,533,729
Intersegment Revenues	80,729	153,727	(234,456)	—
Operating Revenues	$ 3,047,804	$ 720,381	$ (234,456)	$ 3,533,729
Net Operating Margin	$ 927,061	$ 355,870	$ (288,547)	$ 994,384
2001				
Unaffiliated Revenues	$ 3,824,658	$ 454,011	$ —	$ 4,278,669
Intersegment Revenues	63,394	192,662	(256,056)	—
Operating Revenues	$ 3,888,052	$ 646,673	$ (256,056)	$ 4,278,669
Net Operating Margin	$ 180,790	$ 363,822	$ (161,587)	$ 383,025
2000				
Unaffiliated Revenues	$ 2,701,373	$ 365,613	$ —	$ 3,066,986
Intersegment Revenues	46,385	212,727	(259,112)	—
Operating Revenues	$ 2,747,758	$ 578,340	$ (259,112)	$ 3,066,986
Net Operating Margin	$ 1,307,980	$ 308,188	$ (123,224)	$ 1,492,944

Schedule of Amount and Allocation of Plant Investment

Federal Columbia River Power System
As of Sept. 30, 2002 — Thousands of dollars

Schedule A

		Commercial Power			Irrigation (unaudited)		
	Total Plant	Completed Plant	Construction Work in Progress	Total Commercial Power	Returnable from Commercial Power Revenues	Returnable from Other Sources	Total Irrigation
Bonneville Power Administration							
Transmission Facilities	$ 5,482,014	$ 5,097,741	$ 384,273	$ 5,482,014	$ —	$ —	$ —
Bureau of Reclamation							
Boise	118,268	16,576	1,263	17,839	639	65,671	66,310
Columbia Basin	1,903,883	1,215,976	27,777	1,243,753	493,430	143,154	636,584
Green Springs	35,500	11,161	—	11,161	9,934	8,070	18,004
Hungry Horse	148,423	120,731	817	121,548	—	—	—
Minidoka-Palisades	381,854	110,381	54	110,435	386	72,505	72,891
Yakima	227,818	6,160	13	6,173	13,025	127,511	140,536
Total Bureau Projects	2,815,746	1,480,985	29,924	1,510,909	517,414	416,911	934,325
Corps of Engineers							
Albeni Falls	48,141	40,420	3,106	43,526	—	—	—
Bonneville	1,371,207	873,380	93,574	966,954	—	—	—
Chief Joseph	618,659	565,479	13,006	578,485	—	163	163
Cougar	93,683	20,311	31,178	51,489	—	3,288	3,288
Detroit-Big Cliff	69,365	40,998	2,241	43,239	—	5,050	5,050
Dworshak	376,065	314,733	5,172	319,905	—	—	—
Green Peter-Foster	93,617	49,722	3,635	53,357	—	6,210	6,210
Hills Creek	50,242	17,665	892	18,557	—	4,616	4,616
Ice Harbor	212,364	149,316	3,910	153,226	—	—	—
John Day	645,959	477,534	21,094	498,628	—	—	—
Libby	574,639	430,031	2,636	432,667	—	—	—
Little Goose	250,475	207,582	1,431	209,013	—	—	—
Lookout Point-Dexter	107,949	49,603	6,369	55,972	—	1,489	1,489
Lost Creek	149,751	26,978	10	26,988	—	2,186	2,186
Lower Granite	405,213	329,697	2,007	331,704	—	—	—
Lower Monumental	268,538	224,511	1,376	225,887	—	—	—
McNary	366,624	284,030	8,818	292,848	—	—	—
The Dalles	404,420	303,324	51,805	355,129	—	—	—
Lower Snake	260,079	256,065	1,445	257,510	—	—	—
Columbia River Fish Bypass	800,264	247,942	515,454	763,396	—	—	—
Total Corps Projects	7,167,254	4,909,321	769,159	5,678,480	—	23,002	23,002
AFUDC on Direct Funded Projects	16,822	—	16,822	16,822	—	—	—
Irrigation Assistance at 12 Projects having no power generation	201,179	—	—	—	157,144	44,035	201,179
Total Plant Investment	15,683,015	11,488,047	1,200,178	12,688,225	674,558	483,948	1,158,506
Repayment Obligation Retained by Columbia Basin Project	4,639	2,836 (a)	—	2,836 (a)	1,803	—	1,803
Investment in Teton Project (b)	79,107	—	7,269	7,269	56,573	3,681	60,254
Total	**$15,766,761**	**$11,490,883**	**$1,207,447**	**$12,698,330**	**$732,934**	**$487,629**	**$1,220,563**

(a) Amount represents joint costs transferred to Bureau of Sports Fisheries and Wildlife. This is included in other assets in the accompanying balance sheets.

(b) The $7,269,000 commercial power portion of the Teton project is included in other assets in the accompanying balance sheets. Teton amounts exclude interest totaling approximately $2.2 million subsequent to June 1976, which was charged to expense.

Non-reimbursable *(unaudited)*

	Navigation	Flood Control	Fish and Wildlife	Recreation	Other	Percent Returnable from Commercial Power Revenues
Bonneville Power Administration						
Transmission Facilities	$ —	$ —	$ —	$ —	$ —	100.00%
Bureau of Reclamation						
Boise	—	—	—	—	34,119	15.62%
Columbia Basin	—	16,590	6,073	172	711	91.24%
Green Springs	—	—	—	—	6,335	59.42%
Hungry Horse	—	26,875	—	—	—	81.89%
Minidoka-Palisades	—	64,404	2,570	10,471	121,083	29.02%
Yakima	—	2,432	50,365	284	28,028	8.43%
Total Bureau Projects	—	110,301	59,008	10,927	190,276	72.04%
Corps of Engineers						
Albeni Falls	180	269	—	4,166	—	90.41%
Bonneville	400,925	—	—	1,266	2,062	70.52%
Chief Joseph	—	—	4,977	6,034	29,000	93.51%
Cougar	548	38,358	—	—	—	54.96%
Detroit-Big Cliff	219	20,857	—	—	—	62.34%
Dworshak	9,618	31,463	—	15,079	—	85.07%
Green Peter-Foster	365	30,322	—	1,693	1,670	56.99%
Hills Creek	630	26,439	—	—	—	36.94%
Ice Harbor	55,623	—	—	3,515	—	72.15%
John Day	90,943	18,025	—	11,954	26,409	77.19%
Libby	—	95,141	876	15,318	30,637	75.29%
Little Goose	34,739	—	—	4,119	2,604	83.45%
Lookout Point-Dexter	745	49,141	—	602	—	51.85%
Lost Creek	—	53,022	24,507	29,418	13,630	18.02%
Lower Granite	52,593	—	—	13,074	7,842	81.86%
Lower Monumental	39,370	—	—	2,864	417	84.12%
McNary	68,856	—	—	4,920	—	79.88%
The Dalles	47,191	—	—	2,078	22	87.81%
Lower Snake	2,569	—	—	—	—	99.01%
Columbia River Fish Bypass	34,230	2,638	—	—	—	95.39%
Total Corps Projects	839,344	365,675	30,360	116,100	114,293	79.23%
AFUDC on Direct Funded Projects	—	—	—	—	—	100.00%
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	78.11%
Total Plant Investment	839,344	475,976	89,368	127,027	304,569	85.21%
Repayment Obligation Retained by Columbia Basin Project	—	—	—	—	—	100.00%
Investment in Teton Project (b)	—	9,151	—	2,433	—	80.70%
Total	**$839,344**	**$485,127**	**$89,368**	**$129,460**	**$304,569**	**85.2219%**

Report of Independent Accountants

PRICEWATERHOUSECOOPERS

To the Administrator of the
Bonneville Power Administration,
United States Department of Energy

In our opinion, the accompanying balance sheets and the related statements of changes in capitalization and long-term liabilities and of revenues and expenses, of cash flows present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2002 and 2001, the results of its operations, and its cash flows for each of the three years in the period ended September 30, 2002, and the changes in its capitalization and long-term liabilities for each of the two years in the period ended September 30, 2002, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of FCRPS' management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The Schedule of Amount and Allocation of Plant Investment as of September 30, 2002 (Schedule A) is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information, except for that portion marked "unaudited," on which we express no opinion, has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

Portland, Oregon
December 16, 2002

Federal Repayment

Revenue Requirement Study

The revenue requirement study demonstrates repayment of federal investment, and it reflects revenues and costs consistent with the 1996 Wholesale Power and Transmission Rate Filing. FERC granted final approval for proposed Power and Transmission rates on April 4, 1997, for fiscal years 1997 through 2001 (75 FERC 62,010 (1997)).

BPA submitted a separate Transmission and Ancillary Services Rate Filing in 2000 for fiscal years 2002 through 2003, and a Power Rate Filing in 2001 for fiscal years 2002 through 2006. FERC granted final approval of BPA's Transmission and Ancillary Services rates on May 7, 2001, for fiscal years 2002 through 2003, 62 FERC 62,094 (2001). On June 29, 2001, FERC granted final approval for the acceleration of the Ancillary Services and Control Area Services Rate (ACS-02) for Generation Imbalance Service (GIS), 95 FERC 62,286 (2001); and on October 11, 2001, FERC granted final approval for corrections of the ACS-02 rate, 97 FERC 62,020 (2001). FERC granted interim approval for proposed Power rates on Sept. 28, 2001, for fiscal years 2002 through 2006, 96 FERC 61,360 (2001).

Repayment Demonstration

BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects that are beyond the ability of the 22 irrigation water users to repay. These requirements are met by conducting power repayment studies including schedules of payments at the proposed rates to demonstrate repayment of principal within the allowable repayment period.

Since 1985, BPA has prepared separate repayment demonstrations for generation and transmission in accordance with an order issued by the Commission on Jan. 27, 1984 (26 FERC 61,096).

Repayment Policy

BPA's repayment policy is reflected in its generation and transmission revenue requirements and respective rate levels. This policy requires that FCRPS revenues by function be sufficient to:

1. Pay the cost of obtaining power through purchase and exchange agreements (nonfederal projects).
2. Pay the cost of operating and maintaining the power system including payments related to the underfunded status of the CSRS plan.
3. Pay interest on and repay outstanding bonds issued to the Treasury to finance transmission system construction, conservation, environmental, direct-funded Corps and Reclamation improvements, and fish and wildlife projects.
4. Pay interest on the unrepaid investment in power facilities financed with appropriated funds. (Federal hydroelectric projects were all financed with appropriated funds, as were BPA transmission facilities constructed before 1978.)
5. Pay, with interest, any outstanding deferral of interest expense.
6. Repay the power investment in each federal hydroelectric project with interest within 50 years after the project is placed in service (except for the Chandler project, which has a legislated repayment period of 66 years).
7. Repay each increment of the investment in the BPA transmission system financed with appropriated funds with interest within the average service life of the associated transmission plant (40 years).
8. Repay the appropriated investment in each replacement at a federal hydroelectric project within its service life.
9. Repay construction costs at federal reclamation projects that are beyond the ability of the irrigators to pay and are assigned for payment from commercial power net revenues within the same period available to the water users for making payments. These periods range from 40 to 66 years, with 50 years being applicable to most of the irrigation payment assistance.

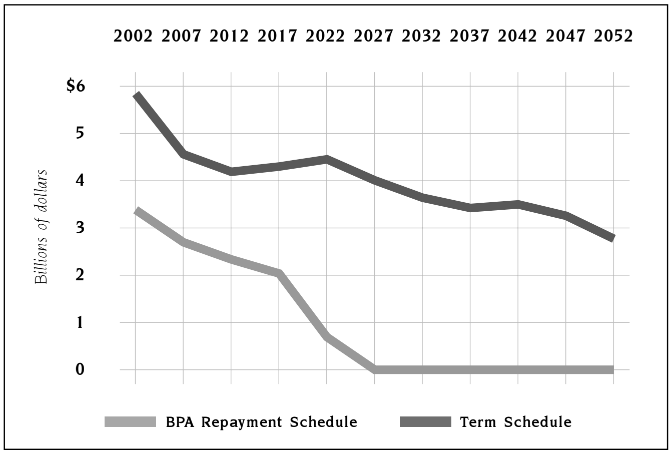
Investments bearing the highest interest rate will be repaid first, to the extent possible, while still completing repayment of each increment of investment within its prescribed repayment period.

Repayment Obligation

BPA's rates must be designed to collect sufficient revenues to return separately the power and transmission costs of each FCRPS investment and each irrigation assistance obligation within the time prescribed by law. If existing rates are not likely to meet this requirement, BPA must reduce costs, adjust its rates, or both. However, total irrigation assistance payments cannot require an increase in the BPA power rate level. By comparing BPA's repayment schedule for the unrepaid capital appropriations and bonds with a "term schedule" it is demonstrated that the federal investment will be repaid within the time allowed. A term schedule represents a repayment schedule whereby each capitalized appropriation or bond would be repaid in the year it is due.

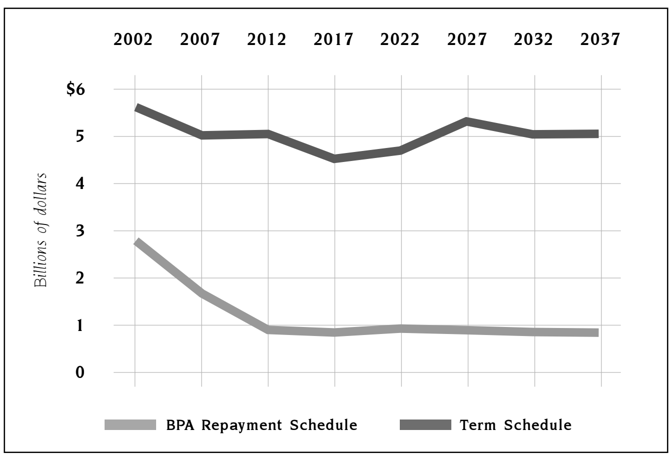
Unrepaid Federal Generation Investment

Includes future replacements



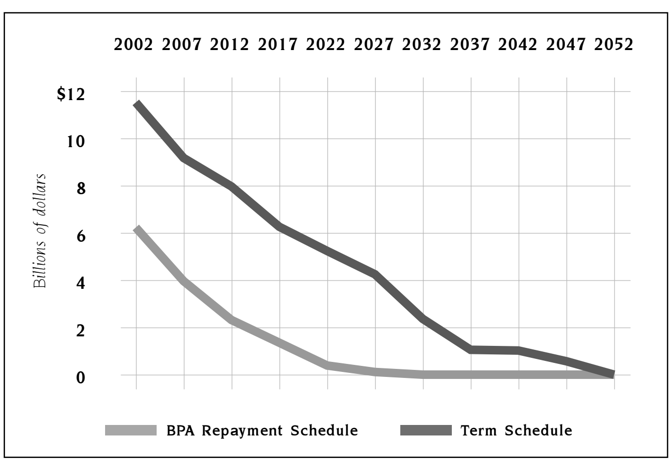
Unrepaid Federal Transmission Investment

Includes future replacements



Unrepaid Federal Investment

Excludes future replacements



Reporting requirements of Public Law 89-448 are met so long as the unrepaid FCRPS investment and irrigation assistance resulting from BPA's repayment schedule are less than or equal to the allowable unrepaid investment in each year. While the comparison is illustrated by graphs representing total FCRPS generation and total FCRPS transmission investment, the actual comparison is performed on an investment-by-investment basis.

Repayment of FCRPS Investment

The graphs for Unrepaid Federal Generation and Transmission Investment illustrate that unrepaid investment resulting from BPA's generation and transmission repayment schedules is less than the allowable unrepaid investment. This demonstrates that BPA's rates are sufficient to recover all FCRPS investment costs on or before their due dates.

The term schedule lines in the graphs show how much of the obligation can remain unpaid in accordance with the repayment periods for the generation and transmission components of the FCRPS. The BPA repayment schedule lines show how much of the obligation remains to be repaid according to BPA's repayment schedules. In each year, BPA's repayment schedule is ahead of the term schedule. This occurs because BPA plans repayment both to comply with obligation due dates and to minimize costs over the entire repayment study horizon (40 years for transmission, 50 years for generation). Repaying highest interest-bearing investments first, to the extent possible minimizes costs. Consequently, some investments are repaid before their due dates while assuring that all other obligations are repaid by their due dates. These graphs include forecasts of system replacements during the repayment study horizon necessary to maintain the existing FCRPS generation and transmission facilities. The Unrepaid Federal Investment graph displays the total planned unrepaid FCRPS obligations compared to allowable total unrepaid FCRPS investment omitting future system replacements. This demonstrates that each FCRPS investment through fiscal year 2002 is scheduled to be returned to the U.S. Treasury within its repayment period and ahead of due dates.

If, in any given year, revenues are not sufficient to cover all cash needs, including interest, any deficiency becomes an unpaid annual expense. Interest is accrued on the unpaid annual expense until paid. This must be paid from subsequent years' revenues before any repayment of federal appropriations can be made.

BPA Executives and Offices

as of December 31, 2002

Corporate Executives

Stephen J. Wright
Administrator & Chief Executive Officer

Steven G. Hickok
Deputy Administrator

Ruth B. Bennett, acting
Chief Operating Officer

Allen L. Burns, special assignment
Industry Restructuring

Terence G. Esvelt
Senior Vice President,
Employee & Business Resources

Randy A. Roach, acting
Senior Vice President, General Counsel

James H. Curtis
Vice President, Finance;
and Chief Financial Officer

Therese B. Lamb, acting
Vice President, Environment, Fish & Wildlife

Pamela J. Marshall
Vice President, Strategic Planning

Lynda B. Stelzer
Vice President, Shared Services

Jeffrey K. Stier
Vice President, National Relations

BPA Offices

BPA Headquarters
905 N.E. 11th Ave.
P.O. Box 3621
Portland, OR 97208
(503) 230-3000

Washington, D.C. Office
Forrestal Bldg., Room 8G-061
1000 Independence Ave., S.W
Washington, DC 20585
(202) 586-5640

BPA Public Information Center
P.O. Box 12999
Portland, OR 97212
(503) 230-3478
1-800-622-4519

Power Business Line Executives

Paul E. Norman
Senior Vice President, Power Business Line

Alexandra B. Smith
Vice President, Requirements Marketing

Gregory K. Delwiche
Vice President, Generation Supply

Stephen R. Oliver
Vice President, Bulk Marketing &
Transmission Services

Michael J. Weedall
Vice President, Energy Efficiency

Power Business Line's Customer Service Centers

Bend CSC
1011 S.W. Emkay Dr., Suite 211
Bend, OR 97702
(541) 318-1680

Big Arm CSC
P.O. Box 40
Big Arm, MT 59910
(408) 849-5034

Burley CSC
2700 Overland
Burley, ID 83318
(208) 678-9481

Eastern Area CSC
707 W. Main St., Suite 500
Spokane, WA 99201
(509) 358-7409

Richland CSC
Kootenai Bldg., Room 215
North Power Plant Loop
Richland, WA 99352
(509) 372-5771

Seattle CSC
909 First Ave., Suite 380
Seattle, WA 98104
(206) 220-6759

Western Area CSC
905 N.E. 11th Ave.
Portland, OR 97232
(503) 230-3584

Transmission Business Line Executives

Mark W. Maher
Senior Vice President, Transmission Business Line

Alan L. Courts
Vice President, Engineering & Technical Services

Frederick M. Johnson
Vice President, Transmission Field Services

Charles E. Meyer
Vice President,
Transmission Marketing & Sales

Marg C. Nelson
Vice President,
Business Line Management & Services

Vickie A. VanZandt
Vice President, Operations & Planning

Transmission Business Line's Regional Offices

TBL Headquarters
P.O. Box 491
Vancouver, WA 98666-0491
(360) 418-2000

Eugene Region
86000 Hwy. 99 S.
Eugene, OR 97405
(541) 465-6991

Idaho Falls Region
1350 Lindsay Blvd.
Idaho Falls, ID 83402
(208) 524-8770

Olympia Region
5240 Trosper St. S.W.
Olympia, WA 98512-5623
(360) 704-1600

Redmond Region
3655 W. Highway 126
Redmond, OR 97756
(541) 548-4015

Snohomish Region
914 Ave. D
Snohomish, WA 98290
(360) 568-4962

Spokane Region
2410 E. Hawthorne Rd.
Mead, WA 99201
(509) 358-7358

Walla Walla Region
6 W. Rose St., Suite 400
Walla Walla, WA 99362
(509) 527-6238

Photo Captions and Credits

Page 3
Stephen J. Wright, BPA administrator
photo by Scott Hoyle

Page 5
Lower Granite Dam in the distance.
photo by Jan Stoffels

Page 6
Andrea Cortez, secretary
photo by Sherry Lind

Page 7
A 30-ton wind turbine nacelle is lifted to its final destination 60 meters in the air at the Condon Wind Project in Oregon.
photo by Tom Osborn

BPA electricians Bev Williamson and Doug Goldsmith suit up to inspect a faulted 500-kV breaker at Pearl Substation.
photo by Rick Stone

Page 8
BPA Operator Apprentice Lauren Catterlin looks at earthquake damage to a surge suppressing resistor at Raver Substation.
photo by Kathi Youngs

Greg Vassallo (left) and Willy Merris (right) take a Sno-Cat up to Wolf Mountain Radio Station, east of Oakridge, Ore., to check out an emergency generator alarm.
photo by John Costello

Page 9
BPA welder
photo by Bob Heims (retired)

Page 10
Dave Fitzsimmons, PBL account executive, talks with Joe Nadal of Pacific Northwest Generating Cooperative, a BPA customer.
photo by Sherry Lind

Page 11
BPA linemen replace a tower on the Olympia-White River 230-kV line in Washington.
photo by Joe Murphy (retired)

New high-voltage submarine cable is brought on floats to an island shore providing power to the San Juan Islands in Washington.
photo by Mark Korsness

Page 12
Mira Vowles, general engineer, shows off a fuel cell.
photo by Sherry Lind

Page 13
Worker knocks ice off a microwave dish cover at Mt. Spokane.
photo by Jeffery Neyman

Becky Clark and Ray Classen check out energy-efficient compact fluorescent light bulbs.
photo by Jean Oates

Page 14
Two generations of BPA linemen: John Hester, Senior (middle) and brothers John Hester, Jr. (left), and Shane Hester (right).
photo by Sherry Lind

TBL Dispatcher Bill Hayden at generation console in Dittmer Control Center.
photo by Earl Kolanda

Page 15
Gus Rojas, power operations specialist
photo by Sherry Lind

Page 16
Anne Jernberg, electrician
photo by Sherry Lind

Page 17
Vic deHackbeil, sheet metal mechanic
photo by JoAnne Sutton

Erecting transmission towers.
photo by Monte Ward (retired)

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

www.bpa.gov

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