Bonneville Power Administration **2000 Annual Report**

BPA 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.

Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

www.bpa.gov

DOE/BP-3355 February 2001 3M

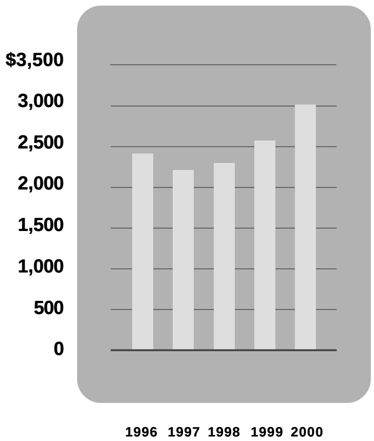
Table of Contents

Bonneville Power Administration

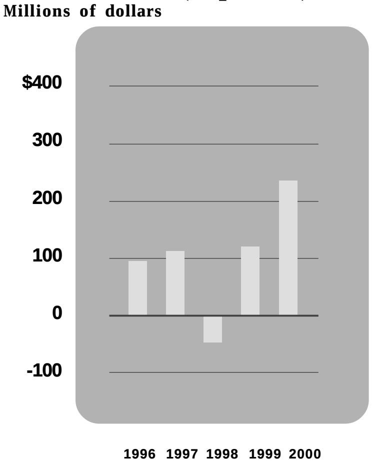
Financial Highlights

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

Total Operating Revenues
Millions of dollars



Net Revenues (Expenses)
Millions of dollars



Operating Results
Thousands of dollars

	2000	1999
Total operating revenues	$ 3,040,169	$ 2,618,879
Total operating expenses	2,464,542	2,139,940
Net operating revenues	575,627	478,939
Net interest expense	334,650	355,653
Net revenues	$ 240,977	$ 123,286

End of Fiscal Year
Thousands of dollars

	2000	1999
Total assets (net of accumulated depreciation)	$16,842,567	$16,773,177
Total capitalization and liabilities		
Accumulated net revenues (expenses)	$ 132,810	$ (108,167)
Federal appropriations	4,566,011	4,498,483
Capitalization adjustment	2,328,540	2,396,014
Long-term debt	2,513,200	2,515,200
Nonfederal projects debt	6,408,865	6,692,041
Other	893,141	779,606
	$16,842,567	$16,773,177

Employees
Staff years

2000	1999
2,732	2,727

Letter to the President

Dear Mr. President:

The agency is well on its way to accomplishing all the major goals it set for itself three years ago: completing BPA's Subscription program to secure the benefits of the Federal Columbia River Power System for the people of the Pacific Northwest; establishing a regional independent grid operation that will include BPA's transmission facilities; creating a regional fish and wildlife plan that is legally defensible, scientifically credible and implementable; advancing innovations in sustainable, market-enhancing energy technologies; and implementing policies and practices to make BPA a high-performing workforce and workplace.

And the agency is in good financial shape — we ended FY 2000 with reserves of $811 million after net revenues of $241 million.

BPA's financial results were a result both of the agency being good at what it does and of its being lucky in gaining its first experience with extremely volatile power prices in a good water year. BPA was somewhat buffered in 2000 from the huge price swings that sent the West reeling because the flexibility of its hydro system provided the ability to adjust, within certain limitations, to fluctuating markets and load demands. But the agency is not immune to these market changes — its power purchase costs reached record levels during the year. BPA will likely be more exposed to those high prices in the future as it responds to its customer requests for greater amounts of power service.

While we shouldn't expect to be lucky with streamflows or the severity of winter weather, we can definitely work to put ourselves in a position to take advantage of any good fortune that comes our way and to moderate the effects of any bad. This is familiar terrain. BPA has always been a regional shock absorber. But, in FY 2000, we had to work particularly hard for our successes and take on some very difficult issues in order to help the region deal with the uncertainties of deregulation. We prepared two rate cases — one for power and one for transmission — and brought our Subscription effort to completion.

Subscription is at the center of our existence. It determined how much power our customers want, balanced its distribution equitably by customer class, laid the financial foundation for our salmon recovery efforts and stimulated new investment in conservation and renewable generation resources that are important to the region's future.

After completing both the Power Business Line and the Transmission Business Line rate cases, we began an unprecedented but necessary step to amend the power rate case. We realized that some key assumptions we had built into that case in the months before the summer price leaps in California were obsolete. Customers were requesting far more power from us for the 2002-2006 period than we anticipated, which increased the amount of power we will have to buy on the market to augment our federal power. And market power was going to be far more costly than anyone had imagined just a few months earlier.

Our customers moved closer to us as we made these tough decisions. For, even if our power were to cost more after the amended rate case than they expected when they signed Subscription contracts, they knew our prices still would be substantially below market. As the year ended, customers were lined up to sign contracts for 3,000 more megawatts than the federal system can be depended on to produce. Most customers were committing to buy for 10 years — the longest-term contract BPA offered. This was a powerful vote of confidence in BPA's ability to continue to be the least expensive and most reliable source of power for many years to come.

Reliability was the watchword for BPA's participation with eight regional investor-owned utilities in a filing to the Federal Energy Regulatory Commission to form a regional transmission organization to be called RTO West. This Northwest organization represents a dramatic departure from the way transmission services have been provided historically. We believe that RTO West is the region's best chance to assure and enhance needed transmission reliability in the deregulating environment.

And we can be proud of our accomplishments in "greening" ourselves and the Northwest. We were rated first in the nation for the way we have used marketing to finance new renewables projects, primarily wind. And we have received regional attention for the amount of "green" power we buy from retail utilities for service to our own facilities throughout the Pacific Northwest. We are also a leading promoter of fuel cell development and use.

Another reason BPA did well in FY 2000 is that we have taken care of business internally. We maintain aggressive targets for controlling internally managed costs, and we meet them. To help us in the future, we invested in an enterprise-wide software system to support our business operations. The system integrates our business operations in a way that enables us to understand and manage more effectively our financial and human resources. Bringing up the system's components is a major continuing effort, but we are far ahead of the industry track record for success in implementing such systems. In fact, we are being visited by utilities looking to emulate our success.

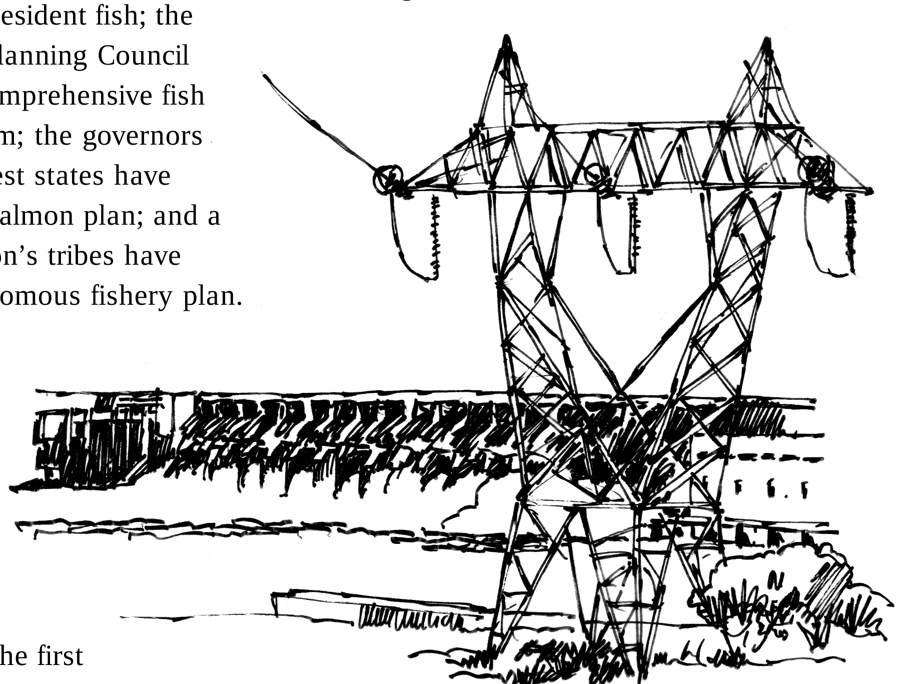
Taking care of business internally also means focusing new effort in FY 2001 on employee development. BPA has employees who are motivated and committed to bring value to the Northwest. It is important that we provide them with the right training so they can adapt their skills to our rapidly changing technical and operating environment.

And there was some success in another arena that is very important to the agency and the region — recovery of threatened and endangered fish, both anadromous and resident. In FY 2000, we made real progress toward our goal of creating a unified recovery plan. BPA and eight other federal agencies in the region created a new framework for recovery strategies. The region still has multiple plans — the National Marine Fisheries Service has prepared a new biological opinion on how the Columbia River system should be operated to protect anadromous fish, and the U.S. Fish and Wildlife Service has done the same for resident fish; the Northwest Power Planning Council has amended its comprehensive fish and wildlife program; the governors of the four Northwest states have weighed in with a salmon plan; and a number of the region's tribes have presented an anadromous fishery plan. But there is beginning to be convergence and a recognition of the need for consistency and even, ultimately, unification. NMFS, for example, is for the first time asking the Northwest Power Planning Council program to encompass its biological opinion.

There is a new reason for optimism. A number of salmon runs were at levels in 2000 that were higher than we have seen in several decades.

As the entire electricity industry ventures into the uncharted territory of energy restructuring, BPA is acting to secure for the people of the Pacific Northwest the essential values of reliability, low cost and environmental quality that have been the hallmarks of the Federal Columbia River Power System. The challenges are daunting, but we are addressing them with confidence.

A lot of that confidence comes from the track record the agency established under former Administrator Judi Johansen during her tenure from June 1998 to



September 2000 when she left the agency to accept a position in the private sector. The agency will miss her greatly, but she left a cadre of talented employees, a strong management team and a substantial financial base for the agency.

Cordially,

Stephen J. Wright
Acting Administrator and CEO

Review of 2000

The Bonneville Power Administration was fortunate during fiscal year 2000. Its foundation in hydroelectric generation positioned it to be less affected by the price spikes that hit the West Coast in the wake of California's experiment in deregulation than utilities that relied more on power generated by natural-gas-fired combustion turbines or on purchased power.

Wenatchee apples and pears

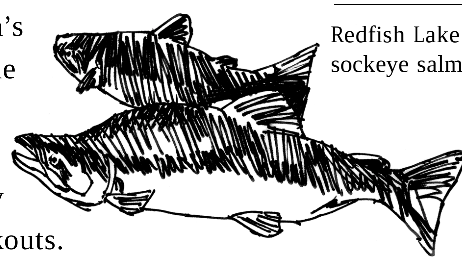
The agency had a solid year, which positions it well to handle continuing market volatility in the 2001 fiscal year. The agency ended FY 2000 with net revenues of $241 million and financial reserves of $811 million in cash and unused borrowing authority.

The agency's financial success allowed it to work on the important tasks necessary to position it for the future as industry restructuring continues on its erratic course. Much of the agency's attention in FY 2000 was focused on rate cases for both the Transmission Business Line and the Power Business Line, on the Subscription process through which customers contract for BPA power, on attempts to create a unified salmon recovery plan and on steps that will lead to a regional transmission organization. All these issues are important to the region.

Price volatility hits the West Coast

The first hint of what the summer would hold came on May 26 when the California Independent System Operator (CAISO) declared a stage 2 emergency, which led to curtailment of interruptible loads in California. In late June, power prices peaked at levels as high as $1,400 a megawatt-hour in California as demand far exceeded supply. It got worse in August. CAISO declared multiple stage 2 emergencies and brushed up against stage 3, in which rolling involuntary blackouts could hit areas of the state.

BPA, fulfilling what it sees as its public service role, scrambled successfully to find sufficient transmission and generation to come to California's aid. As a result, the CAISO credited BPA for helping the state narrowly avert rolling blackouts.



Redfish Lake sockeye salmon

The volatile market affects the power rate case

BPA was not immune to the turmoil in California or to power shortages of its own. In both June and August, BPA declared operating emergencies and turned to the market. Operating emergencies mean the ability to keep the lights on can only be maintained through the use of extraordinary measures. BPA is required to declare them if it is necessary to modify fish operations in order to meet firm power obligations. BPA and its partners in the Federal Columbia River Power System operate the hydro system in a way that gives first priority to aiding threatened and endangered anadromous and resident fish. Both times BPA declared operating emergencies during the year, the modifications lasted only a few hours and had negligible effect on fish.

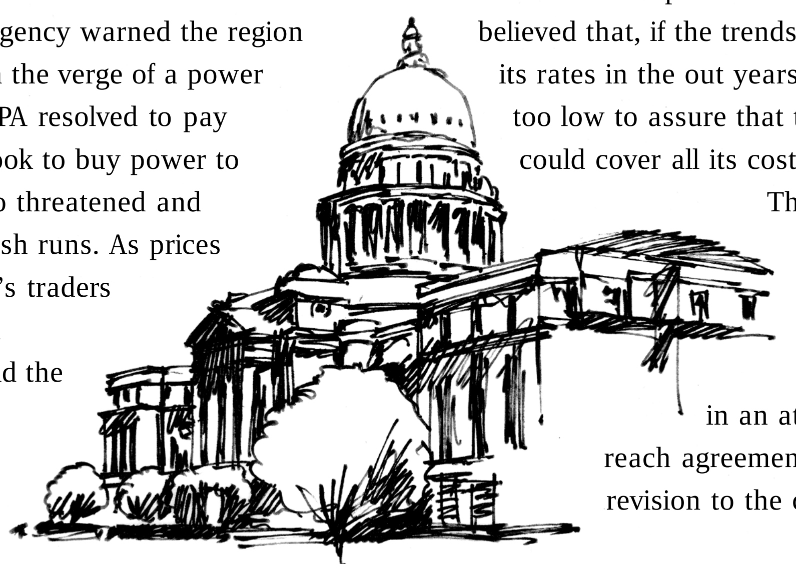
August was the most volatile month. On August 18, the Columbia Generating Station (the nuclear plant formerly known as WNP-2) was forced to reduce generation to 60 percent of capacity for two weeks before shutting down for repairs. That came on top of low summer flows on the Columbia and the decision of regional fish and wildlife managers to use more of the available water in early August rather than in late August. As a result, the agency faced the possibility it would be 1,500 average megawatts short of meeting firm load for the rest of the month. The agency warned the region that it was on the verge of a power emergency. BPA resolved to pay whatever it took to buy power to avoid harm to threatened and endangered fish runs. As prices went up, BPA's traders found enough power to avoid the emergency.

The result was that BPA spent over $331 million to buy power in August and September. This was a powerful reminder that, while BPA's hydroelectric base cushions it from some of the extremes of the power market, it is by no means insulated from the market.

The power rate case. The Power Business Line entered FY 2000 with its rate case for fiscal years 2002-2006 well under way. After holding many public hearings, the PBL issued its formal initial rate proposal in late November 1999.

The agency issued a power rates record of decision on May 15, 2000, sent it to the Federal Energy Regulatory Commission for review and set about signing contracts. As FERC was reviewing the record of decision, the staff and managers of the PBL and the agency conferred on the implications of the late summer price volatility and the upward trend in natural gas prices. In a move to assure BPA's fiscal integrity, the agency asked FERC to suspend consideration of the earlier filing while BPA called for a reconsideration of parts of the case. BPA believed that, if the trends continued, its rates in the out years would be too low to assure that the agency could cover all its costs.

The Power Business Line met with customers in an attempt to reach agreement on a revision to the cost



Idaho's state capitol building in Boise

recovery adjustment clause (CRAC) in the 2002-2006 rates. The CRAC is an automatic increase in power rates that is triggered when BPA's actual accumulated net revenues fall below a certain threshold. The goal is to strengthen the agency's ability to recover its costs if the price of purchased power rises beyond the original rate case projections.

Cascade Douglas fir

Customer groups could not agree on a settlement, and, as the fiscal year came to an end, the agency began preparations to conduct a limited rate process in FY 2001.

Subscription

Rate making set the price for BPA power while the Subscription process addressed how much power various customer groups would commit to purchase from BPA. Subscription and the rate case also addressed incentives for conservation and renewables development and provided the underpinning for the agency's ability to meet its fish and wildlife obligations. Given the widely differing points of view in the region on these matters, it was no surprise that both processes proved to be controversial.

Customers had until Oct. 31, 2000, to subscribe to (sign contracts for) BPA power for periods as short as three and as long as 10 years.

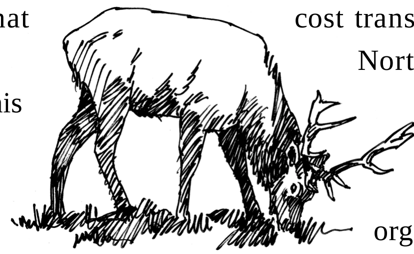
They subscribed for 3,000 average megawatts more power than the federal system produces on a firm-planning basis. This will require BPA to go to the market to meet its Subscription obligations.

TBL plans historic changes and completes its rate case

While the power price spikes and California's supply problems grabbed headlines, BPA's Transmission Business Line was working with eight investor-owned utilities (Avista Corp., Idaho Power Co., Montana Power Co., Nevada Power Co., PacifiCorp, Portland General Electric, Puget Sound Energy and Sierra Pacific Power) to create a historic restructuring of the regional transmission system.

As the fiscal year came to a close, the Transmission Business Line and the IOUs were working diligently to meet an Oct. 16, 2000, filing deadline with the Federal Energy Regulatory Commission. The filing was the initial step in forming a regional transmission organization (RTO) to be called RTO West.

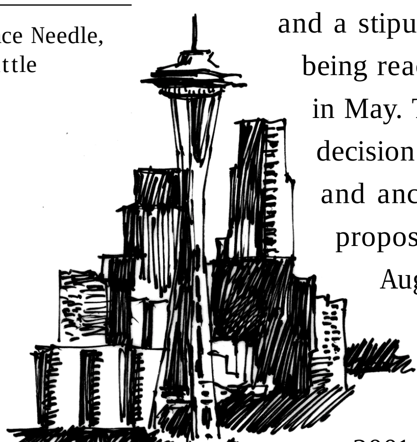
BPA believes that an RTO is the best way to assure reliability in an environment of open competition for the supply of power. The Federal Energy Regulatory Commission issued an order in December 1999 calling on all transmission providers in the country to create and join RTOs. Even though BPA is not a jurisdictional utility — that is, one that falls under FERC's jurisdiction for this purpose — it voluntarily complied. BPA is guided by a set of principles designed to assure that its traditional public responsibilities will be maintained under an RTO.



Montana elk

The transmission rate case. FY 2000 also was an unusual year for rate cases. The agency conducted two: one for power and one for transmission. This reflects the administrative separation of the power merchant function from the transmission function under FERC orders 888 and 889 of 1996.

During FY 2000, the Transmission Business Line conducted its first rate case as a separate business line. The process went smoothly with the initial rate proposal being published in March and a stipulated agreement being reached with the parties in May. The final record of decision on the transmission and ancillary service rate proposal was signed on Aug. 18 and was submitted to FERC for approval to be effective Oct. 1, 2001, for a two-year period. Settling quickly and without a full-blown rate case allowed BPA's customers to have a clearer idea of the total cost of wholesale power while going into Subscription. Even with rate increases, BPA retained its position as a very low-cost transmission provider in the Pacific Northwest.



Space Needle, Seattle

The two years will act as a bridge to the time that a regional transmission organization will be functioning.

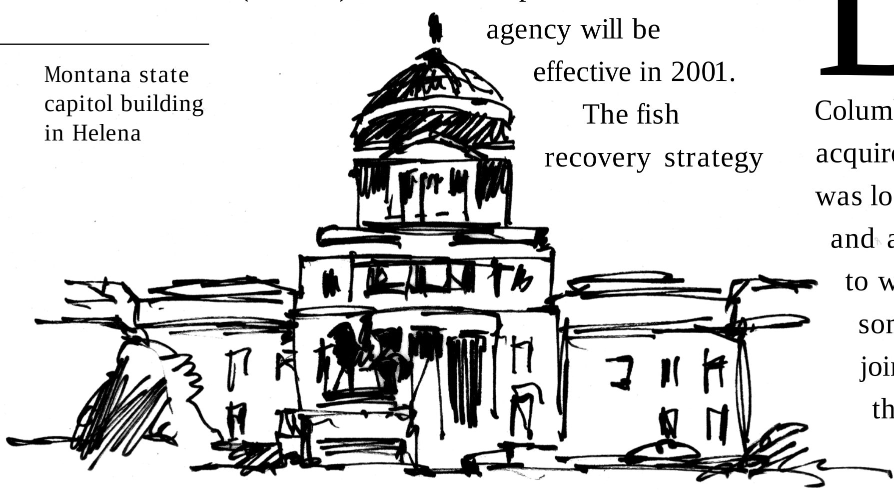
Fish programs

BPA continues to pursue its goal of a unified fish plan for the region that contains a scientific underpinning, measurable goals and reliable funding.

BPA was an active member of the Federal Caucus, the nine federal agencies working on Columbia Basin fish issues — the Bureau of Indian Affairs, Bureau of Land Management, Bureau of Reclamation, BPA, Environmental Protection Agency, National Marine Fisheries Service, U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service and U.S. Forest Service. The Caucus produced a conceptual recovery strategy for anadromous and resident fish listed under the Endangered Species Act. Early versions of the strategy were referred to as the "All-H" paper because it addresses habitat, harvest, hydropower operations and hatchery issues. The strategy includes actions to help listed fish in every stage of their lifecycle. The Caucus held 15 public hearings on the strategy across the region during February and March of

2000. The final version of the plan was released in late 2000 after technical review by the region's states and tribes.

As called for in the Endangered Species Act, the National Marine Fisheries Service and the U.S. Fish and Wildlife Service each issue what is called a "biological opinion" that outlines how the Federal Columbia River Power System should be operated to protect ESA-listed anadromous (NMFS) and resident (USFWS) fish. A new opinion from each agency will be effective in 2001. The fish recovery strategy calls for the use of performance standards over an eight-year period to measure the success of the various recovery actions and projects. This structure sets clear goals to align actions and priorities and provides accountability for BPA rate-payers and U.S. taxpayers who share the bill.



Montana state capitol building in Helena

FY 2000 was an encouraging year for salmon. Because of improvements in ocean conditions and the investments made in the hydro system in the mid-1990s, the region saw some of the best salmon runs in decades. For example, a remarkable 237 sockeye returned to Redfish Lake in Idaho's Stanley Basin by Sept. 5. In contrast, between 1991 and 1999, a total of 23 returned, including the famous "Lonely Larry," the only sockeye to return in 1992.

Wildlife programs

BPA's wildlife program is habitat based, which means its goal is to replace habitat lost to the reservoirs behind the Federal Columbia River Power System dams. The acquired habitat is to be similar to what was lost in terms of the species it sustains and as close geographically as possible to what was lost. The agency made some large strides in FY 2000. BPA joined with the Confederated Tribes of the Warm Springs Reservation to buy a 24,000-acre ranch in Wheeler County, Oregon. The ranch sits on Pine Creek, a tributary of the John Day River, and is home to at least 36 animal and plant species listed as sensitive, threatened or endangered, including one of the few remaining native steelhead populations in the lower John Day Basin. BPA will work with the tribes to develop a management plan to restore the land.

In March, BPA funded the purchase of the 1,760-acre Logan Valley Ranch. The

Mount St. Helens, Washington

Burns Paiute Tribe will hold title to the land and manage it. The ranch is located in the Malheur National Forest in eastern Oregon and is home to several species

Idaho spuds

that are listed or proposed for listing, including bull trout, bald eagle, redband trout and Canadian lynx.

In an effort designed specifically for spring chinook but that also will benefit wildlife, BPA worked with ranchers, the Shoshone-Bannock Tribe, the Idaho Department of Fish and Game and the Northwest Power Planning Council to remove cattle from 48,000 acres of prime salmon habitat along Elk Creek in Bear Valley. BPA compensated ranchers for giving up their grazing permits on federal rangelands along the tributary of the Middle Fork of the Salmon River.

BPA also is sponsoring watershed improvement programs throughout the region. Such improvements will help both fish and wildlife.

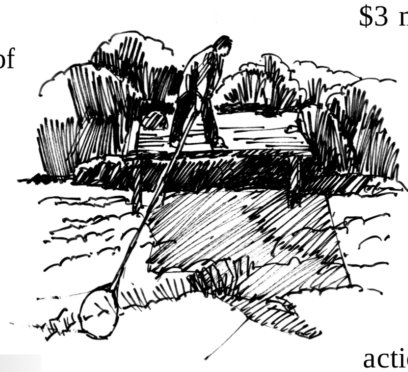
Energy Efficiency

Much of BPA's attention to energy efficiency played out in the power rate case. The two major related areas in the rate case are the conservation and renewables discount and what is termed "conservation augmentation."

The discount program is designed to provide market incentives for the agency's power customers to invest in incremental conservation and new renewable resources. BPA's power customers would receive a 0.5 mill discount off their base power rate for expenditures on qualifying measures. This could result in as much as $40 million of discount funds being invested in new conservation or renewables projects each year of the 2002-2006 rate period.

BPA anticipates exceeding the council's conservation savings target of 166 aMW for the next rate period. These cost-effective conservation savings will contribute to BPA's effort to augment its basic power supply during the same time period.

The Northwest Energy Coalition applauded BPA for its decision to invest $3 million annually in the next rate period on low-income weatherization through funding to local community action agencies.



Fishing platforms, Sherars Falls

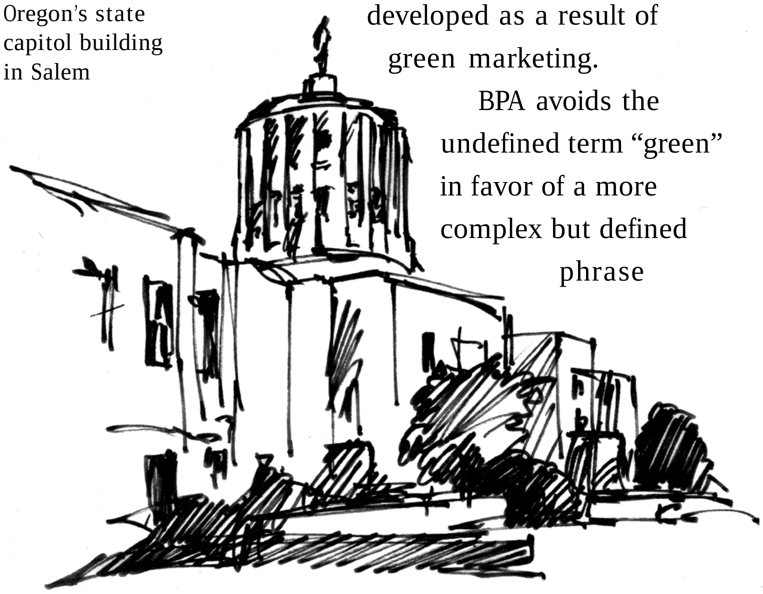
BPA had proposed merging the program into the conservation and renewables discount but changed the proposal in acknowledgment of the proven success of the community action agencies in delivering this service.

Environmentally preferred power

BPA turned a deeper shade of green in FY 2000.

In July, the National Renewable Energy Laboratory announced that BPA is tops in the country in new renewable resource capacity developed as a result of green marketing.

BPA avoids the undefined term "green" in favor of a more complex but defined phrase "environmentally preferred power." EPP is power generated by a renewable source at a defined low impact on the environment. BPA is currently marketing EPP from solar and wind projects and from hydroelectric projects that achieve the low level of impact endorsed by a number of environmental groups. A geothermal plant was being studied as the year ended. BPA's wind portfolio of 34 megawatts is growing. The agency added capacity to a project in Wyoming and is considering projects in Oregon, Washington and Montana. One of the projects could grow to 300 megawatts.



Oregon's state capitol building in Salem

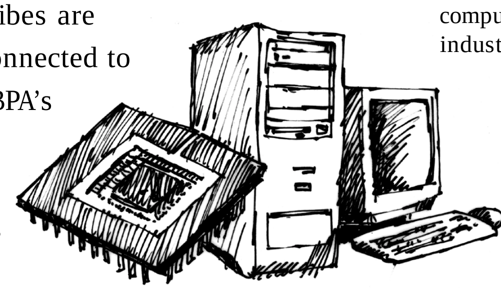
To boost renewables, BPA is funding wind research through two Oregon State University programs and solar research through the University of Oregon Solar Radiation Data Center. BPA also has signed on to the Northwest Solar Alliance along with the states of Idaho, Montana, Oregon and Washington and the U.S. Department of Energy's Seattle office to promote solar applications in the region. BPA is buying output from the city of Ashland's solar array — a Solar Pioneers Initiative.

And BPA walks its talk. In August, PacifiCorp, the regional investor-owned utility from which BPA buys power for its Portland headquarters and several other facilities, recognized BPA as the largest buyer of the IOU's Blue Sky wind product. BPA has committed to buy at least 5 percent of its power from renewable sources for any BPA facility where such products are available.

Tribal relationships

BPA maintains liaisons with the tribes in the region to keep them in the know about BPA activities that can affect them.

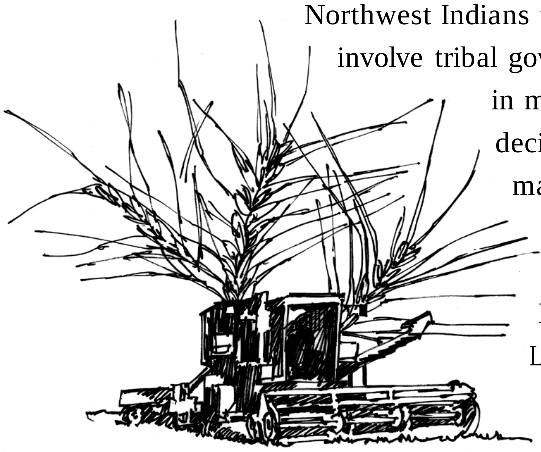
The tribes are deeply connected to most of BPA's fish and wildlife programs and are active participants in many projects (see the *Wildlife programs* section on page 10 for examples). But there are many other



Northwest computer industry

programs and projects that can affect the tribes, such as construction projects and culturally important sites on and off reservations.

In FY 2000, BPA awarded a two-year $100,000 grant to the Affiliated Tribes of Northwest Indians to help involve tribal governments in mutual decision-making with the Transmission Business Line on upcoming policy decisions. The agency made a similar grant in December 1998 to ATNI to help improve tribal understanding of and participation in BPA's power-related issues.



Palouse wheat

The agency also awarded a $40,000 grant for an education program to better connect Native Americans with natural resource careers. The grant, which went to the Earth Conservation Corps Northwest/Salmon Corps, will fund a director of education and training for a year.

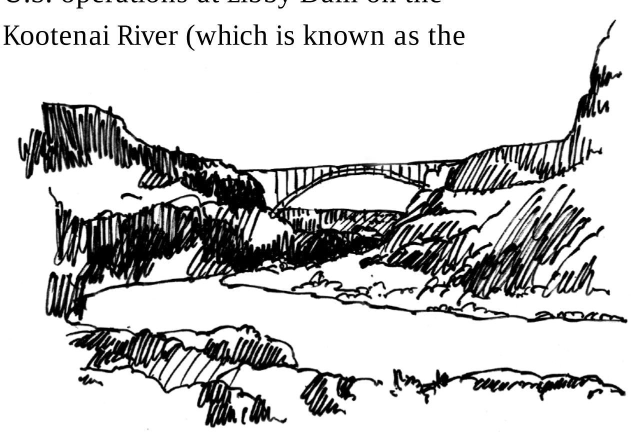
BPA has provided tribal representatives with support to help them follow the many proposals on salmon and steelhead recovery efforts over the years. And this year BPA has continued to provide consulting help as many tribal governments evaluate whether they should or could form utilities to serve tribal members.

Perhaps the most important part of the BPA-tribal relationship is the ongoing government-to-government consultations the agency supports. Former Administrator Judi Johansen took a personal interest in assuring that the consultations occurred. Some of the consultations are about specific issues, such as this summer's Federal Caucus salmon recovery proposal and how RTO West may affect the tribes, while others are more general and devoted to relationship building.

International issues

BPA has a little-known role in international relations. BPA and the U.S. Army Corps of Engineers make up the U.S. "entity" implementing the Columbia River Treaty with Canada. The treaty determines how certain hydroelectric projects on the Columbia River in Canada are coordinated with the river operations in the United States.

After more than five years of talks, the U.S. and Canadian entities reached agreement on handling issues regarding the U.S. operations at Libby Dam on the Kootenai River (which is known as the



Perrine Bridge, Twin Falls, Idaho

Kootenay River where it flows through Canada). In addition to power production in the U.S., the dam is being operated to protect salmon and white sturgeon. In the spirit of cooperation that the U.S. and Canada have enjoyed in over 30 years of implementing the treaty, the U.S. has agreed to let Canada mitigate for any power losses it experiences from the salmon and sturgeon operations.
B.C. Hydro accomplishes this through provisional drafts of Arrow Reservoir in Canada and power exchanges with BPA that don't involve any economic loss to BPA.

Y2K

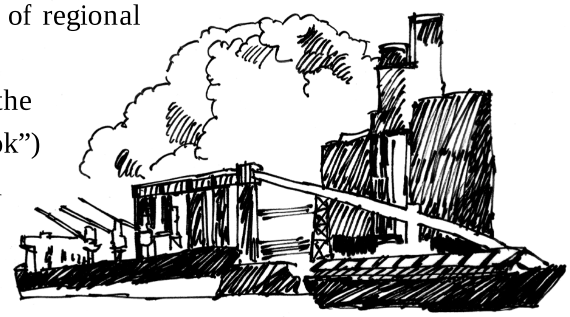
At this distance, it is hard to remember all the anxiety surrounding the rollover to the year 2000. BPA's employees spent thousands of hours bringing its computer, transmission and business systems into Y2K readiness.

The agency and its employees then went into New Year's Eve in a heightened state of alert because a transmission tower on BPA's direct-current intertie to California had been toppled on the night of Dec. 30. Rather than an act of terrorism, the incident in Central Oregon turned out to be simple vandalism. That was the most eventful part of the transition as all of BPA's efforts to prepare for the evening turned out to be as successful as they were thorough.

Big Sky cattle

Anticipating the future

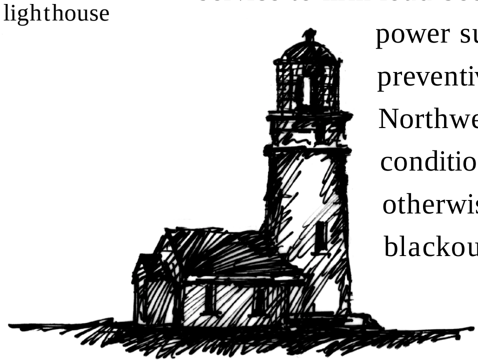
The summer shortages in California were a portent of what could happen to the Northwest during winter months. For several years BPA's annual assessment of regional loads and resources (the "White Book") has warned of the growing possibility of winter power shortages. That concern was supported by a Northwest Power Planning Council study released in December 1999 that found the region has, roughly, a one in four chance of being unable to meet demand in a cold, dry winter. The study said that getting the region up to historic industry reliability levels would require bringing almost 3,000 megawatts of new capacity on line. The council observed that market forces would not bring that much new generation into operation before 2004 at the earliest.



West Coast ports

BPA and the Northwest Power Planning Council hosted a "Keep the Lights On" conference in February 2000. Over 200 people met to examine power grid reliability and the status of generation supply. Many attendees agreed on the situation: deregulation is under way but not complete so there is conflict about what will be handled by the market and what will be compelled by the regulators. They also agreed on the need for conservation and demand management to help address the current deficit. But the question of who is in charge remains.

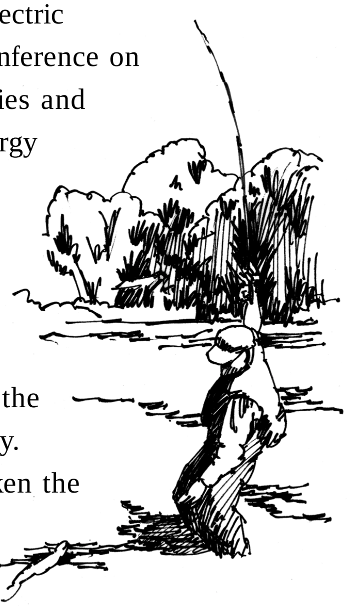
To deal with the problems this deficit could bring, BPA collaborated with regional, state and utility entities to establish a Pacific Northwest Winter 2000-2001 Energy Emergency Plan. The plan is intended to provide a coordinated regionwide approach to averting winter emergencies that would threaten loss of service to firm load because of insufficient power supply. It focuses on preventive actions the Northwest can take under conditions that would otherwise lead to rolling blackouts.



Oregon lighthouse

BPA launched a Demand Exchange Program to purchase the curtailment of energy use at critical times. Under the program, customers agree to voluntary load curtailment for a price. The program began as a pilot in FY 2000, and by mid-September four customers had agreed to provide up to 125 megawatts of load curtailment for from four to six hours at a stretch with even greater potential for single-hour curtailments. The agency's goal is to sign up as much as 300 megawatts of single-hour curtailment by the end of the calendar year and up to 800 megawatts of four-to-six-hour potential over the next three years.

BPA also co-sponsored the second "Electric Revolution" conference on new technologies and renewable energy sources. The conference is a way of spotlighting advances that can transform the energy industry.

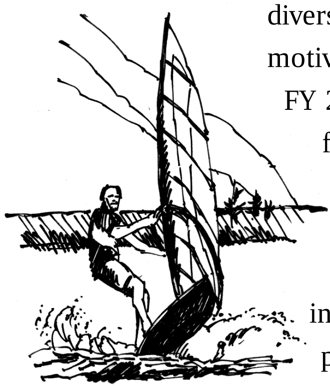


Montana fly fishing

BPA has taken the lead in developing one of those new technologies. BPA's fuel cell development participation came into its own this year. The first of 10 alpha test systems was installed in early summer in Central Oregon. By September, six of the test cells were cranking out kilowatts in utilities and in homes served by BPA's utility customers. BPA told its fuel-cell supplier, IdaTech (formerly called Northwest Power Systems), to design and build 50 beta test fuel cell systems. These next-generation fuel cells will begin to be placed with consumers in several of BPA's public utility customer service areas in 2001.

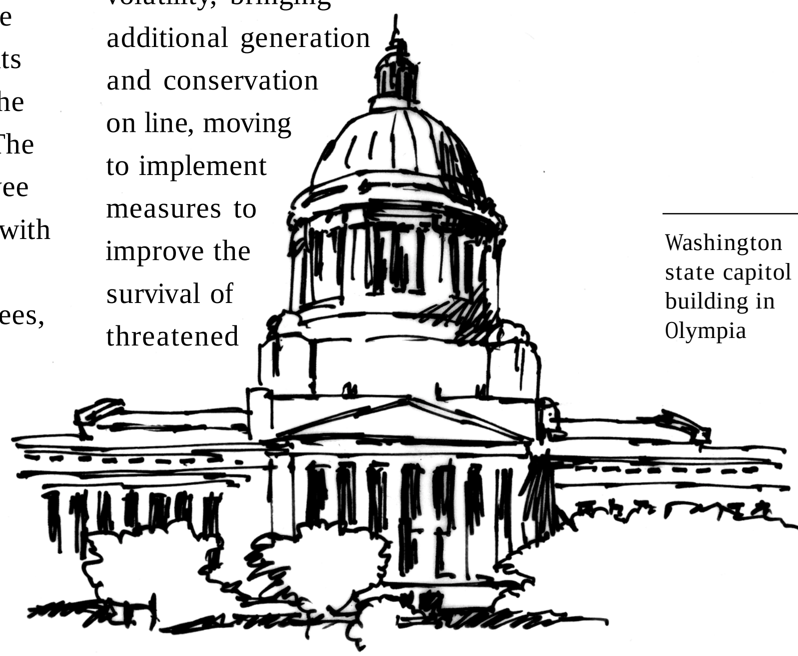
High-performing organization

Since 1998, BPA has been honing its vision of what it takes to become a high-performing organization (HPO). The agency believes that it can only be effective in the current state of the energy industry with a diverse, talented and motivated workforce. FY 2000 was the first year in which the agency created measurable indicators of its progress in the HPO arena. The indicators were in the areas of employee development, recognition, connection with the agency's business, fair and open systems, communication with employees, management focus on employees and demonstrations of personal integrity, trust and respect. The agency made improvements in all areas. The focus of efforts for FY 2001 is on employee development.


Columbia Gorge wind surfing

BPA is far more than a utility — the range of issues it deals with extend well beyond simply selling electricity and moving electricity reliably from one place to another. BPA is a unique entity, being a federal agency responsive to a region and being deeply involved in such matters as governance of regional assets and economic stability.

The agency's goal in the coming months is to resolve the power rate case by June. With the rate and Subscription issues behind it, BPA can join the region in resolving issues that are becoming increasingly important — completing work on RTO West, discussing how the region can retain the benefits of the Federal Columbia River Power System in the face of industry restructuring, examining price volatility, bringing additional generation and conservation on line, moving to implement measures to improve the survival of threatened and endangered fish and more.


Washington state capitol building in Olympia

The region expects a lot of the agency, and all employees at BPA will do their best to meet those expectations.

Financial Section

Bonneville Power Administration

Results of Operations

2000 Compared to 1999

The 2000 operating revenues were $3,040 million, an increase of $421 million from the previous year. Despite a slightly below-average water year, revenues were up primarily because market prices for discretionary power sales increased to 29 mills from the previous year average of 20 mills. Net revenues were $241 million in 2000, an increase of $118 million over 1999 and the highest net revenues in nine years.

1999 Compared to 1998

In 1999, operating revenues increased by $306 million from the previous year primarily because of an increase in discretionary power sales. An above average water year resulted in the generation of more power than the previous year and allowed BPA to sell more power in the winter. Net revenues were $123 million in 1999.

Expenses

Total FCRPS operating and net interest expenses increased by $304 million in 2000 to $2,799 million, an increase of 12 percent over the previous year. In 1999, total FCRPS operating and net interest expense was $2,496 million, an increase of 6 percent compared to 1998. Operating expenses increased both years primarily because of an increase in purchased power expense.

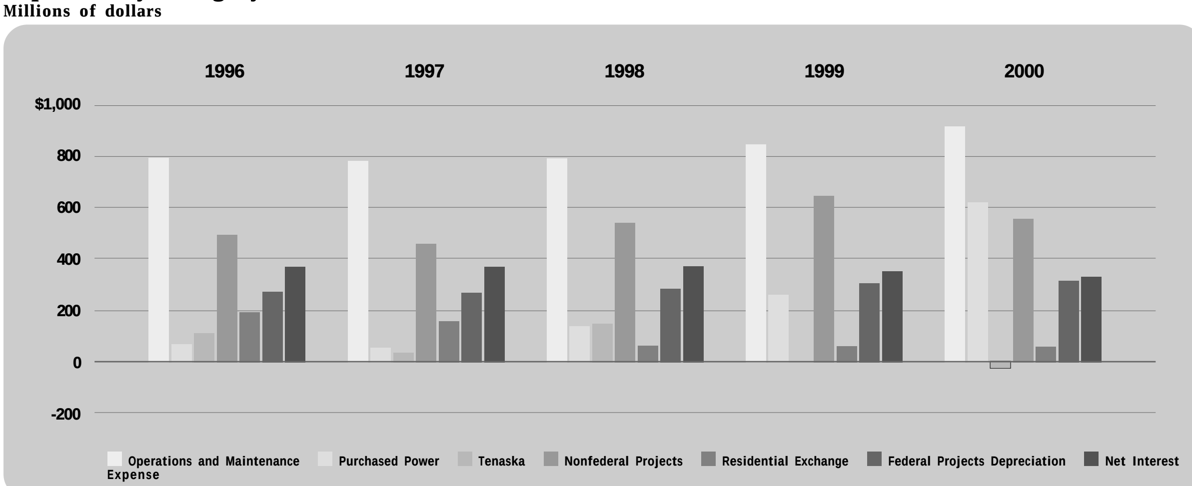
Operation and maintenance costs for the FCRPS rose by $72 million in 2000, an increase of 8 percent. Higher operations and maintenance expenses for BPA were the primary cause for the increase. In 1999, operations and maintenance costs increased by $54 million from the previous year, or 7 percent. The increase was primarily caused by direct funding of Corps of Engineers projects and accelerated decommissioning of the Trojan nuclear plant.

Purchased power costs increased by $360 million, or 136 percent, to $625 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 mills in 1999 to 57 mills in 2000. Purchased power increased by $125 million, or 89 percent to $265 million in 1999.

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. In 1999 debt service on nonfederal projects increased by $106 million, or 19 percent, from $545 million in 1998. Net residential exchange expense was $64 million in 2000, the same as 1999 and 1998. BPA reached settlements with all residential exchange participants in 1998. The settlements satisfied BPA's obligation to participants through at least June 30, 2001, when current residential exchange contracts expire.

Federal projects depreciation was $320 million in 2000, an increase of $11 million compared to 1999. BPA performed a depreciation study in 1999 that resulted in a reduction of the average service life for transmission

Expenses by Category
Millions of dollars



plant from 45 to 40 years and also increased the estimated cost to retire certain classes of plant. As a result, federal projects depreciation was $309 million in 1999, an increase of $21 million from 1998.

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. Net interest expense was $356 million in 1999, a decrease of $20 million compared to 1998. The decrease was a result of lower interest expense on bonds because of refinancings completed in 1998.

Financial Condition

In 2000, BPA's year-end financial reserves — cash and deferred borrowing authority — were $811 million. BPA's financial reserves at the end of fiscal 1999 and 1998 were $670 million and $559 million, respectively.

BPA made its annual payment of $732 million to the U.S. Treasury in 2000, making it the seventeenth consecutive year in which BPA has made its payment on time and in full. The payment consisted of $316 million for principal, $403 million for interest and $13 million for operations and maintenance on the federal dams operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. Payments made in 1999 and 1998 were $628 million and $852 million, respectively.

The funding plan of the administration and Congress for financing BPA's fish and wildlife obligations continues to provide stability to the largest growth area of BPA's expenses through 2001. Five-year contracts with publicly owned customers have stabilized revenues for BPA's largest customer class. BPA ended the year in a solid financial position because of operating cost reductions and an increase in surplus power sales from the previous year.

Rates

In 2000, BPA's rates remained the same as the previous year because in 1997 rates were set for a five-year period. In 1997, BPA's priority firm power rates dropped by an average of 13 percent from 1996 rate levels, the most significant rate decrease in the agency's history. This rate reduction was made possible primarily through internal cost reductions and through the stabilization actions taken by Congress in BPA's fish and wildlife costs. To meet its planning targets for rates, BPA cut planned expenses for 1997–2001 by an average of $600 million per year from the levels in the fiscal year 1995 congressional budget. The new rates were designed to maximize BPA revenues in an increasingly competitive wholesale power market.

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. BPA is in the process of setting rates to cover the additional costs of its Subscription obligations for fiscal years 2002 through 2006.

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 2000, BPA's debt in this category totaled $ 2.5 billion — consistent with 1999 and 1998 levels.

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 at the end of 2000 was $4.6 billion.

In 1997, the U.S. Treasury approved BPA's implementation of the BPA Appropriations Refinancing Act (the Act). The 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 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 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 $6.4 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 2000. Moody's Investors Service maintained a rating of Aa1, the second highest possible rating. Fitch IBCA raised the rating from AA- to AA, citing BPA's success in retaining customers and stabilizing the power system both operationally and financially. Standard & Poor's affirmed their AA- ratings on BPA-backed bonds.

BPA's success depends in part on its ability to manage financial risks. BPA is affected by changes in interest rates and by price risks associated with natural gas and electricity commodities. Flat rate, take-or-pay power sales contracts with aluminum and publicly owned utility customers expire in 2001. These contracts substantially reduce the risk to BPA of fluctuations in sales to those customers and lessen BPA's revenue risk associated with the price of aluminum.

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. Commodity market risk is a consequence of writing options to third parties (subject to variable supply risk), entering into fixed price sales and purchase commitments, and owning and operating generation facilities. BPA actively manages this risk on a portfolio basis to ensure compliance with BPA's risk management policies. At times, futures, swaps and options are used to alter BPA's exposure to these price fluctuations. BPA mitigates credit risk by insisting that counterparties and marketers are significant industry companies that are considered financially strong and establishing and following tailored credit limits for each company.

Management of the market risks associated with this portfolio of transactions 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 market risk on a portfolio basis subject to parameters established by executive management and a risk management committee. Market risks are monitored by individuals who are separated from the group that creates and manages these risk exposures to ensure compliance with BPA's risk management policies.

BPA measures the market risk in its portfolio on a daily, weekly and monthly basis using mark to market (MTM), value at risk (VAR), Monte Carlo simulation and other methodologies. The quantification of market risk using these methods provides a consistent measure of risk across the energy market in which BPA sells and buys. The use of these methods requires a number of key assumptions including 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. The methods used represent an estimate of reasonably possible net losses in earnings that would be recognized on its portfolios assuming hypothetical movements in future market rates 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. Because BPA is primarily selling surplus inventory and not trading, the tests critical to trading organizations are considered less important than regular and rigorous testing for hydro supply conditions. The results of the hydro supply scenario analysis, along with the professional judgments of experienced business and risk managers, are used in conjunction with the market risk measures and to capture additional market-related risks, including credit and event risk.

BPA faces several other uncertainties over the next few years. The deregulated electricity industry market has brought significant uncertainty and volatility to market prices. National and state regulatory changes may lead to further restructuring in the industry, including separating transmission and generation.

Business Solutions Project

In August 2000, BPA implemented the Business Solutions Project (BSP), a new business information system. The new system is an integrated, more efficient system for reporting financial information because it replaces several budget and accounting systems installed in 1986. But the new systems cover more than a replacement of BPA's old financial systems. The BSP is expected to reduce administrative costs and to save information technology costs compared to the previous systems. BPA staff spent two years developing, testing and planning the conversion to the BSP informa-tion system. The implementation has been a success with ongoing testing and system upgrades expected over the next several years.

Performance Measures

Public Responsibilities

BPA surpassed its goal of a composite state/federal entities/constituent satisfaction index of 6.9 to 7.2 when the agency achieved a 7.4 index in 2000. The range for this index is 1 to 10. This measurement shows steady improvement in BPA's relationships with constituents as the score has increased from 6.7 in 1998, to 7.0 in 1999 and to 7.4 in 2000.

A tribal government satisfaction index as measured through a survey was 6.0 in 2000 and did not meet the agency's goal of a satisfaction index of 6.5 to 6.8 (out of a possible score from 1 to 10). Individuals, who participated in the previous year's survey, gave the agency an unchanged average performance score of 6.5. However, additional individuals who participated in the tribal government satisfaction survey for the first time in 2000 gave the agency an average performance score of 5.7.

Finance

BPA met its goal to keep its internally managed costs below $899 million. BPA exceeded its target of having agency net revenues in the range of $1 million to $36 million in 2000. The net revenues for 2000 were $241 million. BPA also met its goal of paying the U.S. Treasury on time and in full.

High-Performance Organization

BPA set a number of targets that focus on how the agency works as an organization.

BPA met its target to have recordable injuries of no more than 1.7 per 100 employees working on BPA facilities and no fatal injuries to employees. The actual rate of recordable injuries was 1.4 per 100 employees.

The agency met its target to implement phase one of the Business Solutions Project.

Customer Satisfaction

BPA met its target of having a customer satisfaction index in a range of 7.3 to 7.6 in 2000. Overall, BPA's customer satisfaction index was 7.5, the same as 1999. The range for this index is 1 to 10. The customer satisfaction index is a composite, weighted index that includes the Power Business Line, Transmission Business Line and Energy Efficiency group ratings.

The Transmission Business Line continued to improve their satisfaction rating this year, increasing their score from 6.9 in 1998, to 7.2 in 1999, to 7.4 in 2000, while the satisfaction rating for the Power Business Line decreased slightly.

Selected Quarterly Information (unaudited)

3 months ended — thousands of dollars

	Dec 31	March 31	June 30	Sept 30	Totals
2000					
Operating revenues	$ 687,487	$ 788,406	$ 629,015	$ 935,261	$ 3,040,169
Operating expenses	471,551	509,155	628,583	855,253	2,464,542
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
1999					
Operating revenues	$ 588,981	$ 773,772	$ 542,195	$ 713,931	$ 2,618,879
Operating expenses	471,481	523,726	522,650	622,083	2,139,940
Net interest expenses	91,082	92,250	91,901	80,420	355,653
Net revenues (expenses)	$ 26,418	$ 157,796	$ (72,356)	$ 11,428	$ 123,286
1998					
Operating revenues	$ 623,740	$ 644,931	$ 466,683	$ 577,899	$ 2,313,253
Operating expenses	415,382	447,680	432,639	690,054	1,985,755
Net interest expenses	95,311	94,518	100,717	85,406	375,952
Net revenues (expenses)	$ 113,047	$ 102,733	$ (66,673)	$ (197,561)	$ (48,454)

Note: BPA's net revenues are normally higher in the first and second quarters of the fiscal year than in the third and fourth. In fall and winter, loads grow to serve Northwest heating needs. In warmer weather, loads decline and BPA spends more in yearly maintenance.

Financial Statements

Balance Sheets

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

Assets

	2000	1999
Utility Plant (Notes 1 and 3)		
Completed plant	$11,105,332	$10,986,446
Accumulated depreciation	(3,583,557)	(3,482,923)
	7,521,775	7,503,523
Construction work in progress	636,000	558,006
Net utility plant	8,157,775	8,061,529
Nonfederal Projects (Note 4)		
Conservation	52,497	56,496
Hydro	235,530	240,610
Nuclear	2,231,874	2,365,135
Terminated nuclear facilities	3,888,964	4,029,800
Total nonfederal projects	6,408,865	6,692,041
Trojan Decommissioning Cost (Note 6)	78,307	85,587
Conservation, net of accumulated amortization of $708,666 in 2000 and $647,892 in 1999 (Notes 1 and 2)	504,504	565,278
Fish and Wildlife, net of accumulated amortization of $105,138 in 2000 and $88,643 in 1999 (Notes 1 and 2)	145,586	148,183
Current Assets		
Cash	848,447	685,014
Accounts receivable	238,179	195,878
Accrued unbilled revenues	118,343	5,200
Materials and supplies, at average cost	64,292	71,077
Prepaid expenses	85,895	82,695
Total current assets	1,355,156	1,039,864
Other Assets	192,374	180,695
	$16,842,567	$16,773,177

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2000	1999
Accumulated Net Revenues (Expenses) (Note 1)	$ 132,810	$ (108,167)
Federal Appropriations (Note 3)	4,499,743	4,476,258
Capitalization Adjustment (Note 3)	2,328,540	2,396,014
Long-Term Debt (Note 2)	2,513,200	2,357,400
Nonfederal Projects Debt (Note 4)	6,053,027	6,379,997
Trojan Decommissioning Reserve (Note 6)	65,707	62,987
Total capitalization and long-term liabilities	15,593,027	15,564,489
Commitments and Contingencies (Notes 6 and 7)		
Current Liabilities		
Current portion of federal appropriations	66,268	22,225
Current portion of long-term debt	—	157,800
Current portion of nonfederal projects debt	355,838	312,044
Current portion of Trojan decommissioning reserve	12,600	22,600
Accounts payable and other current liabilities	372,270	271,571
Total current liabilities	806,976	786,240
Deferred Credits (Note 1)	442,564	422,448
	$16,842,567	$16,773,177

Statements of Revenues and Expenses

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

	2000	1999	1998
Operating Revenues	$3,040,169	$2,618,879	$2,313,253
Operating Expenses			
Operations and maintenance	922,343	850,741	796,789
Purchased power	624,882	265,304	140,732
Tenaska (Note 7)	(26,817)	—	151,307
Nonfederal projects (Note 4)	560,599	651,093	545,366
Residential exchange (Note 5)	63,593	63,619	63,869
Federal projects depreciation	319,942	309,183	287,692
Total operating expenses	2,464,542	2,139,940	1,985,755
Net operating revenues	575,627	478,939	327,498
Interest Expense			
Interest on federal investment:			
Appropriated funds (Note 3)	248,352	249,156	252,517
Long-term debt (Note 2)	115,052	130,916	148,242
Allowance for funds used during construction	(28,754)	(24,419)	(24,807)
Net interest expense	334,650	355,653	375,952
Net Revenues (Expenses)	240,977	123,286	(48,454)
Accumulated net expenses, Oct. 1	(108,167)	(231,453)	(182,999)
Accumulated net revenues (expenses), Sept. 30	$ 132,810	$ (108,167)	$ (231,453)

The accompanying notes are an integral part of these statements.

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, 1998	$ (231,453)	$4,446,103	$2,499,000	$6,949,011	$2,568,184	$16,230,845
Increase (decrease) in federal appropriations:						
Operations & maintenance	—	160,037	—	—	—	160,037
Construction	—	93,364	—	—	—	93,364
Repayment of federal appropriations:						
Operations & maintenance	—	(160,037)	—	—	—	(160,037)
Construction	—	(40,984)	—	—	—	(40,984)
Capitalization adjustment amortization	—	—	—	—	(64,886)	(64,886)
Increase in long-term debt	—	—	192,400	—	—	192,400
Repayment of long-term debt	—	—	(150,000)	—	—	(150,000)
Refinance of long-term debt	—	—	(26,200)	—	—	(26,200)
Net decrease in nonfederal projects debt	—	—	—	(111,785)	—	(111,785)
Repayment of nonfederal projects debt	—	—	—	(145,185)	—	(145,185)
Trojan decommissioning reserve	—	—	—	—	(21,697)	(21,697)
Net revenues	123,286	—	—	—	—	123,286
Balance at Sept. 30, 1999	$ (108,167)	$ 4,498,483	$ 2,515,200	$ 6,692,041	$ 2,481,601	$ 16,079,158
Increase (decrease) in federal appropriations:						
Construction	—	129,953	—	—	—	129,953
Repayment of federal appropriations:						
Construction	—	(62,425)	—	—	—	(62,425)
Capitalization adjustment amortization	—	—	—	—	(67,474)	(67,474)
Increase in long-term debt	—	—	294,300	—	—	294,300
Repayment of long-term debt	—	—	(227,500)	—	—	(227,500)
Refinance of long-term debt	—	—	(68,800)	—	—	(68,800)
Net increase in nonfederal projects debt	—	—	—	40,443	—	40,443
Repayment of nonfederal projects debt	—	—	—	(323,619)	—	(323,619)
Trojan decommissioning reserve	—	—	—	—	(7,280)	(7,280)
Net revenues	240,977	—	—	—	—	240,977
Balance at Sept. 30, 2000	$ 132,810	$4,566,011	$2,513,200	$6,408,865	$2,406,847	$16,027,733

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

	2000	1999	1998
Cash from Operating Activities			
Net revenues (expenses)	$ 240,977	$ 123,286	$ (48,454)
Expenses (income) not requiring cash:			
Depreciation	242,673	233,279	213,799
Amortization of conservation and fish and wildlife	77,269	75,904	73,893
Amortization of nonfederal projects	323,619	145,185	105,227
Amortization of capitalization adjustment	(67,474)	(64,886)	(64,886)
AFUDC	(28,754)	(24,419)	(24,807)
(Increase) decrease in:			
Receivables and unbilled revenues	(155,444)	(13,367)	12,700
Materials and supplies	6,785	3,630	4,086
Prepaid expenses	(3,200)	(1,105)	20,648
Increase (decrease) in:			
Accounts payable	100,699	(43,611)	79,254
Other	8,437	(12,769)	54,007
Cash provided by operating activities	745,587	421,127	425,467
Cash from Investment Activities			
Investment in:			
Utility plant	(310,165)	(215,155)	(141,566)
Conservation	—	(12,484)	(14,154)
Fish and wildlife	(13,898)	(14,748)	(21,995)
Cash used for investment activities	(324,063)	(242,387)	(177,715)
Cash from Borrowing and Appropriations			
Increase in federal appropriations:			
Operations and maintenance	—	160,037	144,887
Construction	129,953	93,364	29,097
Repayment of federal appropriations:			
Operations and maintenance	—	(160,037)	(144,887)
Construction	(62,425)	(40,984)	(35,155)
Increase in long-term debt	294,300	192,400	867,800
Repayment of long-term debt	(227,500)	(150,000)	(211,800)
Refinance of long-term debt	(68,800)	(26,200)	(655,900)
Payment of nonfederal debt	(323,619)	(145,185)	(105,227)
Cash used for borrowing and appropriations	(258,091)	(76,605)	(111,185)
Increase in cash	163,433	102,135	136,567
Beginning cash balance	685,014	582,879	446,312
Ending cash balance	$ 848,447	$ 685,014	$ 582,879

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 the Pacific Northwest 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.

Reclassifications

Certain reclassifications were made to the 1999 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2000. 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 Northwest Power Act and a standard set by the National Energy Policy Act. 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 on less than nine months' notice and may not be increased more than once in a 12-month period. FERC has approved BPA's rates for all fiscal years through Sept. 30, 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.

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 $4.7 billion, shown in the table on page 28, reflect a decrease of $199 million from the prior year. Amortization of these costs aggregating

$276 million in fiscal 2000, $242 million in 1999 and $187 million in fiscal 1998 is reflected in the Statements of Revenues and Expenses.

SFAS 71 Assets
As of Sept. 30 — thousands of dollars

	2000	1999
Nonfederal projects:		
Conservation	$ 52,497	$ 56,496
Terminated nuclear facilities	3,888,964	4,029,800
Trojan decommissioning cost	78,307	85,587
Conservation	504,504	565,278
Fish and wildlife	145,586	148,183
Additional retirement contributions	53,000	36,621
Total	**$4,722,858**	**$4,921,965**

Revenues and Net Revenues

Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenues. BPA operates as two segments: the Power Business Line and the Transmission Business Line. The table in Note 8 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 6.

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) constitute 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 preliminary 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 6.7 percent in 2000, 2.5 percent to 6.8 percent in 1999 and 2.5 percent to 7.4 percent in 1998). Capitalization rates for other construction approximate the cost of borrowing from the U.S. Treasury (6.6 percent in 2000, 6.7 percent in 1999 and 6.6 percent in 1998).

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. A depreciation study was performed in 1999. As a result of the study, the average service life for transmission plant was reduced from 45 to 40 years and the estimated cost to retire certain classes of plant was increased. As a result of the changes in estimated lives and cost to retire, annual depreciation expense increased $21.5 million beginning in 1999. Amortization of capitalized conservation and fish and wildlife costs is computed on the straight-line method based on estimated service lives, which are 20 years for conservation and 15 years for fish and wildlife.

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 ending 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 expected to be made over a period of years as shown in the table on page 29. The payments, if made, will be directly to the U.S. Treasury.

BPA paid approximately $6.0 million, $4.1 million and $2.2 million to the U.S. Treasury during fiscal 2000, 1999 and 1998, respectively. These amounts were recorded as expense when paid. BPA has accrued for $53 million as of Sept. 30, 2000, which represents the additional deferred contribution for fiscal 1998, 1999 and 2000. This amount has been recorded as an SFAS 71 asset on the balance sheet in anticipation of recovery of the costs through rates in the next rate period beginning Oct. 1, 2001. The related liability is included in deferred credits in the accompanying Balance Sheet. At Sept. 30, 2000, BPA has scheduled additional payments totaling $200 million as follows:

Scheduled Additional CSRS Contributions
Millions of dollars

2001	$ 8.0
2002	55.2
2003	35.1
2004	30.9
2005	26.5
2006	23.2
2007	21.1
Total	**$200.0**

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 $403 million in 2000, $421 million in 1999 and $452 million in 1998.

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 $40 million in 2000, $112 million in 1999 and $17 million in 1998.

Concentration of Credit Risks

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 and accrued unbilled revenues. Energy Northwest invests exclusively in U.S. Government securities and agencies. BPA's accounts receivable and accrued unbilled revenues are concentrated with customers who have purchased capacity, energy or other products and services. Generally, these customers are large and stable which BPA does not consider to be a significant credit risk. BPA performs a financial review of new customers and establishes credit limits based on the results of that review. In limited circumstances BPA uses letters of credit or similar security mechanisms for new customers or customers with a limited financial history. As a consequence of the above, FCRPS management does not consider the overall exposure due to concentration of credit risk to be material at Sept. 30, 2000.

However, beginning in fiscal 2001 credit risk is expected to increase due to the energy crisis in California. As a result of high market prices for power the financial condition and stability of some California utilities has deteriorated and their ability to pay has decreased and may continue to decrease.

Deferred Credits

Deferred credits consist of $134.6 million paid to BPA from participants under the 3rd AC intertie capacity agreement, $105.2 million in load diversification fees and other settlement payments for long-term agreements paid to BPA from various customers, $53.0 million in deferred CSRS contributions, $81.2 million in advances from customers for projects which BPA is constructing on their behalf, $20.2 million for the MTM value of written options, and $48.4 million in other miscellaneous long-term liabilities. Deferred 3rd AC intertie capacity payments are recognized as revenue over the estimated 40-year life of the related 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 ending Sept. 30, 2001, while other settlement agreements extend over varying periods through 2019). Advances on projects BPA constructs for customers are either applied against expenditures 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. The current portion of deferred credits to be recorded as revenue in fiscal 2001 is included in accounts payable and other current liabilities in the Balance Sheet.

Hedging and Derivative Instrument Activities

BPA's hedging policy (the 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 uses 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. Recognition of gains or losses on the hedging and derivative instruments prior to adoption of SFAS 133 (discussed below), is deferred until the underlying physical transaction occurs. Swap transactions have maturities less than one year. No Exchange traded futures or options were outstanding at Sept. 30, 2000.

During fiscal 2000, BPA also entered into a small market research program involving the use of both purchased and written options for aluminum, in anticipation of economically hedging new aluminum power sales contracts expected to be signed in fiscal year 2001. As the transaction does not qualify for hedge accounting treatment, the fair values of the purchased and written aluminum options have been recorded in the Balance Sheet at Sept. 30, 2000, and the mark-to-market gains and losses have been recorded in the Statement of Revenues and Expenses for the year then ended.

At Sept. 30, 2000 and 1999, outstanding notional amounts (in megawatt-hours, except for purchased and written aluminum options which are in metric tons) for each type of contract were as follows:

Notional Amounts
As of Sept. 30

Derivative Type	2000	1999
Megawatt-hours		
Swap — BPA pays floating and receives fixed	110,400	269,184
Swap — BPA pays fixed and receives floating	—	48,384
NYMEX futures	—	51,840
NYMEX purchased options	—	17,280
NYMEX written options	—	25,920
OTC purchased options (power)	—	129,600
Metric Tons		
OTC purchased options (aluminum)	156,000	—
OTC written options (aluminum)	156,000	—

At and for the years ended Sept. 30, 2000, 1999 and 1998, 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. The megawatt-hour quantities that BPA sells and the premiums that BPA collects for the sales of these options are priced based on 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. As of Sept. 30, 2000, written call options totaling 30,000 megawatt-hours were outstanding with an average strike price of $61.67 per megawatt-hour. Written put options totaling 190,000 megawatt-hours were outstanding with an average strike price of $64.84 per megawatt-hour. These options expire at various times through Dec. 2000. 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. BPA recognized an immaterial mark-to-market loss during fiscal 2000 and an immaterial mark-to-market loss during fiscal 1999 as a result of the estimated position of outstanding written options.

Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheet as of Sept. 30, 2000 and 1999, excluding those derivatives which are considered to be hedges. 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 EITF 98-10

In Nov. 1998, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) reached a consensus related to the accounting for energy trading activities. In accordance with EITF 98-10, energy trading contracts must be marked to market with the gains and losses included in earnings and separately disclosed in the financial statements. BPA adopted EITF 98-10 on Oct. 1, 1999, as required, and determined that its operations do not meet the guidelines established for trading activities. There was no resulting impact from the adoption of this statement on the FCRPS financial statements.

Adoption of Statement 133

In June 1998, the FASB issued SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. In May 1999, the FASB delayed the required implementation date by one year, making it effective for all fiscal quarters of fiscal years beginning after June 15, 2000 (Oct. 1, 2000 for the FCRPS). In June 2000, the FASB issued SFAS 138, which amends certain sections of SFAS 133. SFAS 133, as amended, requires all derivative instruments be recorded on the balance sheet at their fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, the type of hedge transaction.

Throughout fiscal 2000, management reviewed and evaluated the impact of SFAS 133 on BPA and FCRPS operations. One issue that developed during the evaluation involves the accounting treatment required by SFAS 138 for derivative instruments known as “bookouts” in the electric utility industry. Bookouts are common in the electric utility industry as a power scheduling convenience when two utilities happen to have offsetting transactions for the same delivery period — a sale and a purchase — at the same delivery location. SFAS 138 specifically defines bookout instruments as derivatives and does not allow hedge or accrual accounting to be applied to such instruments. The FASB staff is currently researching concerns expressed by the utility industry related to the accounting treatment of bookouts under SFAS 138. The resolution of the bookout issue and possible change in accounting treatment cannot be determined at this time.

On the date of adoption (Oct. 1, 2000), BPA recorded a $168 million loss primarily attributable to the requirement to account for bookouts as derivatives not qualifying for hedge or accrual accounting treatment. The initial loss will be recorded and presented in fiscal 2001 as a cumulative effect of a change in accounting principle as required by Accounting Principles Board Opinion No. 20, Accounting Changes. Going forward from the date of adoption, BPA estimates the impact of SFAS 133 to be immaterial on a long term basis, as the effects of marking derivatives, including bookout transactions, to market will reverse and eliminate over the terms of the related contracts. However, SFAS 133 is expected to have significant effect in increasing volatility of earnings (losses) on a period to period basis.

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, 2000, $492.8 million of this reserved amount and $2,020.4 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, 2000, for similar maturities exceeds carrying value by approximately $188 million, or 7 percent. BPA's policy is to refinance debt that is callable when associated benefits exceed costs. This table 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
September 1999	none	2002	6.20%	$ 40,000		$ 40,000
November 1999	none	2002	6.40%	40,000		80,000
September 1989	none	2002	8.65%		$66,000	146,000
September 1999	none	2003	6.30%	20,000		166,000
April 2000	none	2003	6.85%	40,000		206,000
July 2000	none	2003	6.95%		32,000	238,000
August 2000	none	2003	6.85%	15,300		253,300
January 1996	none	2003	5.90%	60,000		313,300
May 1999	none	2004	5.95%	26,200		339,500
September 1999	none	2004	6.40%	20,000		359,500
July 2000	none	2004	7.00%	50,000		409,500
January 1997	none	2004	6.80%	30,000		439,500
January 2000	none	2004	7.15%	53,500		493,000
September 2000	none	2005	6.70%	20,000		513,000
May 1997	none	2005	6.90%	80,000		593,000
September 2000	none	2006	6.75%	40,000		633,000
August 2000	none	2006	7.05%	70,000		703,000
August 1997	none	2007	6.65%	111,300		814,300
April 1998	none	2008	6.00%	75,300		889,600
April 1998	none	2008	6.00%	25,000		914,600
August 1998	none	2008	5.75%	40,000		954,600
September 1998	none	2008	5.30%		104,300	1,058,900
February 1993	1998	2008	6.95%	20,000		1,078,900
May 1998	none	2009	6.00%	72,700		1,151,600
May 1998	none	2009	6.00%		37,700	1,189,300
July 1989	none	2009	8.55%		40,000	1,229,300
August 1995	2000	2010	7.20%	35,000		1,264,300
May 1998	none	2011	6.20%	40,000		1,304,300
January 1996	2001	2011	6.70%		30,000	1,334,300
November 1996	2001	2011	6.95%	40,000		1,374,300
September 1998	none	2013	5.60%		52,800	1,427,100
January 1998	none	2013	6.10%	60,000		1,487,100
August 1993	1998	2013	6.75%		40,000	1,527,100
February 1999	none	2014	5.90%	60,000		1,587,100
January 1994	1999	2014	6.75%		50,000	1,637,100
May 1995	2000	2015	7.50%	35,000		1,672,100
November 1996	2001	2016	7.20%		40,000	1,712,100
July 1995	2000	2025	7.70%	50,000		1,762,100
August 1995	2000	2025	7.70%	65,000		1,827,100
April 1998	2008	2028	6.65%	50,000		1,877,100
August 1998	none	2028	5.85%	106,500		1,983,600
August 1998	none	2028	5.85%	112,300		2,095,900
May 1998	2008	2032	6.70%	98,900		2,194,800
August 1993	1998	2033	6.95%	110,000		2,304,800
October 1993	1998	2033	6.85%	108,400		2,413,200
October 1993	1998	2033	6.85%	50,000		2,463,200
January 1994	1999	2034	7.05%	50,000		2,513,200
				$ 2,020,400	**$ 492,800**	**$ 2,513,200**

(a) The weighted average interest rate was 6.6 percent on outstanding long-term debt as of Sept. 30, 2000. 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, 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 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 Act.

Amortization of the capitalization adjustment was $67.5 million for fiscal 2000 and $64.9 million for 1999 and 1998. The weighted-average interest rate was 7.1 in 2000, 1999 and 1998.

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.

The table below shows the term repayments on the remaining federal appropriations as of Sept. 30, 2000.

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.

Federal Appropriations
Thousands of dollars

	Term repayments (a)
2001	$ 66,268
2002	23,913
2003	46,687
2004	73,484
2005	110,989
2006+	4,244,670
Total	**$4,566,011**

(a) 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, whether or not the projects are completed or operating. BPA has also acquired all of the output of the Idaho Falls, 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 $174 million in fiscal 2000, $200 million in fiscal 1999 and $180 million in fiscal 1998 for the projects is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $561 million, $651 million and $545 million for fiscal 2000, 1999 and 1998, respectively, is reflected as nonfederal projects expense in the accompanying Statements of Revenues and Expenses. Following restoration of Energy

Northwest's (formerly known as Washington Public Power Supply System) bond rating in late 1988, BPA and Energy Northwest developed a refunding plan to refinance outstanding high-interest-rate net-billed bonds. By the end of fiscal year 2000, 19 advance-refunding sales have been completed. In total, $10.2 billion of refunding bonds have been issued to refinance $8.6 billion of previously outstanding bonds.

The recorded value of all Energy Northwest debt exceeds fair value by $81 million or one percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2000. 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, 2000.

Nonfederal Projects
Thousands of dollars

	Debt Repayments
2001	$ 355,838
2002	268,310
2003	319,801
2004	329,665
2005	280,343
2006+	4,854,908
Total	**$6,408,865**

5. Residential Exchange

As provided for in the Pacific Northwest Electric Power Planning and Conservation Act of 1980, Section 5(c), BPA entered into residential exchange contracts with several electric utilities. These contracts result in payments to each utility, which must be passed through to its qualified residential and irrigation loads, based on the difference between each utility's average cost and BPA's priority firm power rate.

Congress passed legislation in November 1995 that required BPA to pay $145 million in residential exchange benefits in fiscal 1997. The conference report prepared in connection with that legislation states that BPA and its customers, consistent with the Regional Review, should work together to gradually phase out the residential exchange program by Oct. 1, 2001. Termination agreements have been signed by all actively exchanging Pacific Northwest utilities except The Montana Power Co. (which receives no benefits), whereby payments are made by BPA for settlement of the period running from fiscal 1998 through June 30, 2001. Future benefits are fixed by the termination agreements. BPA capitalizes payments made and is amortizing them to expense through the period ending June 30, 2001. Capitalized amounts are included in other assets in the accompanying Balance Sheets. Without future legislation the residential exchange program will revert to the prior methodology on July 1, 2001.

6. 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 to be made 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. The cumulative irrigation assistance payments ultimately could total approximately $863 million and are scheduled over a maximum of 66 years. In fiscal 1997, BPA made a cash distribution of $25 million as scheduled. 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, 2000.

Irrigation Assistance
Thousands of dollars

	Distributions
2001	$ 16,560
2002	—
2003	—
2004	739
2005	—
2006+	820,348
Total	**$ 837,647**

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 $4.3 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $6.3 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $2.4 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 $83.9 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. In June 1999, Energy Northwest submitted a site restoration plan to the state of Washington's Energy Facility Site Evaluation Committee (EFSEC) that complied with EFSEC's requirement to restore the WNP-1 site 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. BPA is required to fund site restoration. The cost of site restoration for WNP-1 is estimated to be $60 million. Management believes that existing funds from the proceeds of previously issued bonds are adequate to cover some of the site restoration costs at WNP-1. The estimated obligation is reflected as part of the nonfederal projects debt balances for WNP-1 and WNP-3 as of Sept. 30, 2000.

Decommissioning costs for Columbia Generating Station (formerly known as WNP-2) 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 NRC requirements. Sinking fund requirements for Columbia Generating Station are based on a Nuclear Regulatory Commission 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, 2000, 1999 and 1998 were approximately $4 million per year. The sinking fund balance at Sept. 30, 2000, is $72 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 $326 million is based on site-specific studies less actual expenditures to date. As of Sept. 30, 2000, BPA's 30-percent share of this estimated remaining liability is $98 million, which has been recorded net of the decommissioning trust fund balance of $20 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 1998, 1999 and 2000. For the period 1995 through 2002, funding for the Trojan decommissioning trust fund is being applied directly to the decommissioning expenses. Contributions to the decommissioning trust fund are made pursuant to the net-billing agreement for the plant. Once prompt decontamination is completed, funding of the trust will resume at a lower contribution level to pay for the delayed demolition. 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. Decommissioning costs are included in operations and maintenance expense in the Statements of Revenues and Expenses.

Environmental Cleanup

From time to time, there are sites where BPA, the 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.

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 commitments under billing credit agreements and other alternative energy programs whereby BPA provides a cost supplement to entities that are involved in alternative energy generation projects. BPA's aggregate cost of these commitments has approximated $17 million, $19 million and $19 million for fiscal 2000, 1999 and 1998, respectively. BPA's continued cost of these commitments is expected to approximate $17 million per year over the next five years. These commitments expire at various periods over the next 20 years.

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. BPA is in the process of setting rates to recover the additional costs of its Subscription obligations for fiscal years 2002 through 2006. BPA also enters into purchase commitments to purchase power at future dates when BPA forecasts a shortage of generating capability and prices are favorable. Further, BPA enters into sales commitments to sell expected surplus generating capabilities at future dates. 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.

7. Litigation

Involving the Tenaska Washington Partners, II L.P.

In fiscal 1995 the Tenaska Washington Partners, II L.P. (Tenaska) and Chase Manhattan Bank (Chase) filed suit against BPA for breach of contract and lost revenues. In June 1996, BPA and Chase reached a settlement that resulted in a payment of $115 million by BPA to Chase. In 1997, BPA paid expenses of $38 million, which included some of the subcontractor claims. In fiscal 1998 BPA settled with Tenaska for $158.6 million. BPA has now settled with all litigants of the Tenaska suit and no further exposure exists. In fiscal 2000, BPA sold property acquired as a result of these settlements for a gain of $26.8 million, which is included in operating income in the Statement of Revenues and Expenses.

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.

8. Segments

Adoption of Statement 131

Effective Oct. 1, 1998, the FCRPS adopted SFAS 131, Disclosures about Segments of an Enterprise and Related Information. SFAS 131 establishes standards for the way public business enterprises report information about operating segments, and also requires certain disclosures about products and services, geographic areas of business and major customers. The adoption of SFAS 131 did not affect the FCRPS's financial position or results of operations, but did change business segment information previously reported.

Operating 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 United States Department of Treasury, all cash and cash transactions are also centrally managed. Unaffiliated revenues below 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 $1,493 million for fiscal 2000 ($3,040 million Operating Revenues less $922 million Operations and Maintenance and $625 million Purchased Power Expenses) as shown in the Statement of Revenues and Expenses.

Major Customers

During fiscal 2000, 1999 and 1998, 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
2000				
Unaffiliated Revenues	$ 2,674,556	$ 365,613	$ —	$ 3,040,169
Intersegment Revenues	46,385	212,727	(259,112)	—
Operating Revenues	**2,720,941**	**578,340**	**(259,112)**	**3,040,169**
Net Operating Margin	$ 1,307,980	$ 308,188	$ (123,224)	$ 1,492,944
1999				
Unaffiliated Revenues	$ 2,324,041	$ 294,838	$ —	$ 2,618,879
Intersegment Revenues	42,381	257,296	(299,677)	—
Operating Revenues	**2,366,422**	**552,134**	**(299,677)**	**2,618,879**
Net Operating Margin	$ 1,315,425	$ 320,724	$ (133,315)	$ 1,502,834
1998				
Unaffiliated Revenues	$ 2,016,720	$ 296,533	$ —	$ 2,313,253
Intersegment Revenues	44,030	243,392	(287,422)	—
Operating Revenues	**2,060,750**	**539,925**	**(287,422)**	**2,313,253**
Net Operating Margin	$ 1,049,482	$ 311,123	$ 15,127	$ 1,375,732

Schedule of Amount and Allocation of Plant Investment

Federal Columbia River Power System
As of Sept. 30, 2000 — 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	$ 5,015,832	$ 4,869,167	$ 146,665	$ 5,015,832	$ —	$ —	$ —
Bureau of Reclamation							
Boise	114,115	14,793	—	14,793	25,143	39,946	65,089
Columbia Basin	1,957,650	1,121,159	9,610	1,130,769	592,859	173,818	766,677
Hungry Horse	143,487	115,826	277	116,103	—	—	—
Minidoka-Palisades	385,370	107,529	1	107,530	16,637	61,503	78,140
Yakima	224,443	5,999	—	5,999	12,631	128,170	140,801
Total Bureau Projects	2,825,065	1,365,306	9,888	1,375,194	647,270	403,437	1,050,707
Corps of Engineers							
Albeni Falls	44,782	39,871	1,126	40,997	—	—	—
Bonneville	1,324,528	867,882	52,574	920,456	—	—	—
Chief Joseph	608,167	565,260	2,991	568,251	—	163	163
Cougar	62,514	20,306	13	20,319	—	3,288	3,288
Detroit-Big Cliff	68,482	41,010	1,367	42,377	—	5,046	5,046
Dworshak	370,932	314,612	395	315,007	—	—	—
Green Peter-Foster	92,574	49,767	2,597	52,364	—	6,175	6,175
Hills Creek	49,377	17,518	250	17,768	—	4,605	4,605
Ice Harbor	206,321	147,595	227	147,822	—	—	—
John Day	630,779	471,991	11,813	483,804	—	—	—
Libby	570,138	428,827	711	429,538	—	—	—
Little Goose	248,854	206,846	601	207,447	—	—	—
Lookout Point-Dexter	107,505	51,175	7,939	59,114	—	1,496	1,496
Lost Creek	149,721	26,919	61	26,980	—	2,186	2,186
Lower Granite	402,146	330,397	171	330,568	—	—	—
Lower Monumental	267,254	224,511	93	224,604	—	—	—
McNary	358,309	279,811	4,810	284,621	—	—	—
The Dalles	376,978	298,693	29,137	327,830	—	—	—
Lower Snake	257,413	254,891	634	255,525	—	—	—
Columbia River Fish Bypass	631,245	232,977	361,937	594,914	—	—	—
Total Corps Projects	6,828,019	4,870,859	479,447	5,350,306	—	22,959	22,959
Irrigation Assistance at 12 Projects having no power generation	201,179	—	—	—	157,144	44,035	201,179
Total Plant Investment	14,870,095	11,105,332	636,000	11,741,332	804,414	470,431	1,274,845
Repayment Obligation Retained by Columbia Basin Project	4,639	2,836 (a)	—	2,836	1,803	—	1,803
Investment in Teton Project (b)	79,107	—	7,269	7,269	56,573	3,681	60,254
Total	$14,953,841	$11,108,168	$ 643,269	$11,751,437	$ 862,790	$ 474,112	$1,336,902

(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	—	—	—	—	34,233	35.00%
Columbia Basin	1,000	52,424	6,073	154	553	88.05%
Hungry Horse	—	27,384	—	—	—	80.92%
Minidoka-Palisades	—	64,473	2,557	10,475	122,195	32.22%
Yakima	—	1,965	49,883	238	25,557	8.30%
Total Bureau Projects	1,000	146,246	58,513	10,867	182,538	71.59%
Corps of Engineers						
Albeni Falls	176	265	—	3,344	—	91.55%
Bonneville	400,744	—	—	1,266	2,062	69.49%
Chief Joseph	—	—	4,977	5,776	29,000	93.44%
Cougar	548	38,359	—	—	—	32.50%
Detroit-Big Cliff	219	20,840	—	—	—	61.88%
Dworshak	9,625	31,504	—	14,796	—	84.92%
Green Peter-Foster	365	30,356	—	1,644	1,670	56.56%
Hills Creek	628	26,376	—	—	—	35.98%
Ice Harbor	55,184	—	—	3,315	—	71.65%
John Day	90,775	17,984	—	11,807	26,409	76.70%
Libby	—	94,983	876	14,104	30,637	75.34%
Little Goose	34,688	—	—	4,115	2,604	83.36%
Lookout Point-Dexter	748	45,641	—	506	—	54.99%
Lost Creek	—	53,020	24,506	29,399	13,630	18.02%
Lower Granite	50,797	—	—	12,939	7,842	82.20%
Lower Monumental	39,380	—	—	2,853	417	84.04%
McNary	68,837	—	—	4,851	—	79.43%
The Dalles	47,059	—	—	2,067	22	86.96%
Lower Snake	1,888	—	—	—	—	99.27%
Columbia River Fish Bypass	33,715	2,616	—	—	—	94.24%
Total Corps Projects	835,376	361,944	30,359	112,782	114,293	78.36%
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	78.11%
Total Plant Investment	836,376	508,190	88,872	123,649	296,831	84.37%
Repayment Obligation Retained by Columbia Basin Project	—	—	—	—	—	100.00%
Investment in Teton Project (b)	—	9,151		2,433	—	80.70%
Total	$ 836,376	$ 517,341	$ 88,872	$ 126,082	$ 296,831	84.35%

Report of Independent Accountants

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 revenues and expenses, of cash flows and of changes in capitalization and long-term liabilities present fairly, in all material respects, the financial position of the Federal Columbia River Power System (FCRPS) at September 30, 2000 and 1999, and the results of its operations, cash flows and changes in capitalization and long-term liabilities for each of the three years in the period ended September 30, 2000, 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, 2000 (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 20, 2000

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. The Federal Energy Regulatory Commission granted final approval for proposed rates on April 4, 1997, for fiscal years 1997 through 2001 (75 FERC 62,010).

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.

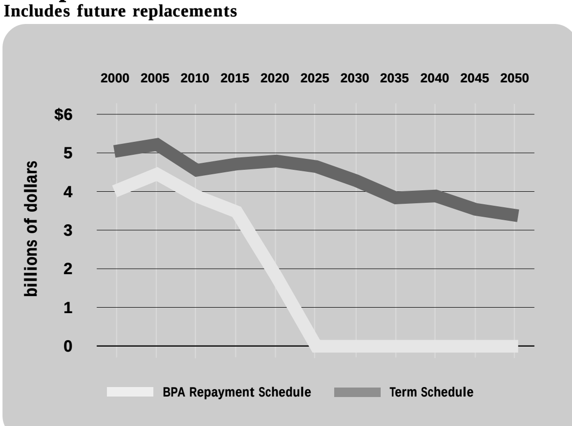
Since 1985, BPA has prepared separate repayment demonstrations for generation and transmission in accordance with an order issued by the Commission on Jan. 27, 1984 (26 FERC 61,096).

Repayment Policy

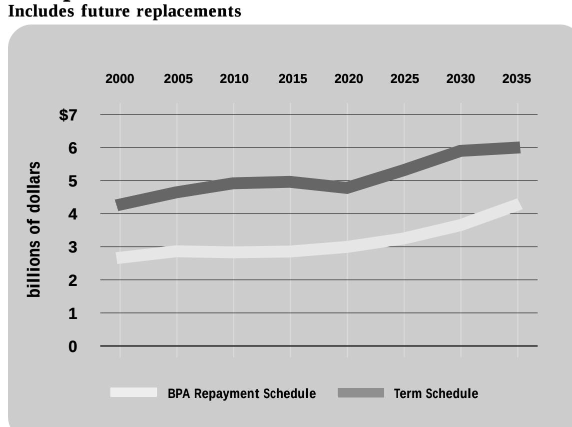
BPA's repayment policy is reflected in its generation and transmission revenue requirements and respective rate levels. This policy requires that FCRPS revenues by function be sufficient to:

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 under-funded 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

Unrepaid Federal Generation Investment
Includes future replacements



Unrepaid Federal Transmission Investment
Includes future replacements



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.

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.

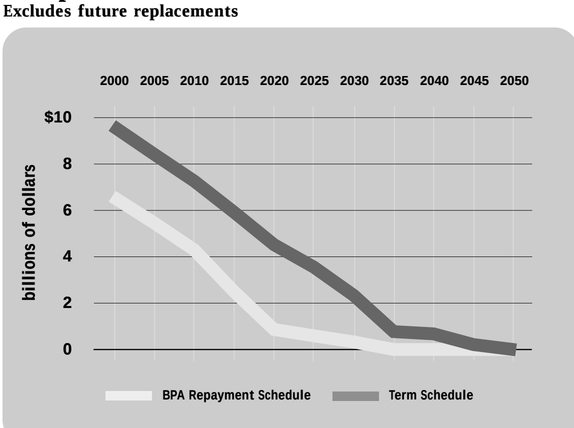
Repayment of FCRPS Investment

The graphs for Unrepaid Federal Generation and Transmission Investment on page 41 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). Costs are minimized by repaying highest interest-bearing investments first, to the extent possible. 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 on this page displays the total planned unrepaid FCRPS obligations compared to allowable total unrepaid FCRPS investment omitting future system replacements. This demonstrates that each FCRPS investment expected through fiscal year 2000 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.

Unrepaid Federal Investment
Excludes future replacements



BPA Executives and Offices

Corporate Executives

Stephen J. Wright, acting
Administrator & Chief Executive Officer

Steve Hickok
Chief Operating Officer

Stephen J. Wright
Deputy Administrator

Terry Esvelt
Senior Vice President,
Employee & Business Resources

Randy Roach, acting
Senior Vice President, General Counsel

Jim Curtis
Vice President, Finance
and Chief Financial Officer

Pam Marshall
Vice President, Strategic Planning

Alexandra Smith
Vice President, Environment,
Fish & Wildlife

Lynda Stelzer
Vice President, Shared Services

Jeff Stier
Vice President, National Relations

Power Business Line Executives

Paul Norman
Senior Vice President,
Power Business Line

Allen Burns
Vice President, Requirements Marketing

Greg Delwiche
Vice President, Generation Supply

Steve Oliver
Vice President, Bulk Marketing &
Transmission Services

John Pyrch, acting
Vice President, Energy Efficiency

Transmission Business Line Executives

Mark Maher
Senior Vice President,
Transmission Business Line

Alan Courts
Vice President, Engineering & Technical
Services

Fred Johnson
Vice President, Transmission Field Services

Chuck Meyer
Vice President, Marketing & Sales

Marg Nelson
Business Line Management & Services

Vickie VanZandt
Vice President, Operations & Planning

BPA Offices

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

Public Information Center
P.O. Box 3621
Portland, OR 97208
(503) 230-7334
1-800-622-4520

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

Power Business Line's Customer Service Centers

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

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

Eastern Area CSC
707 W. Main St., Suite 500
Spokane, WA 99201-0641
(509) 358-7409

Idaho Falls CSC
1350 Lindsay Blvd.
Idaho Falls, ID 83402
(208) 524-8750

Missoula CSC
800 Kensington, Suite 204
Missoula, MT 59801-5631
(406) 329-3060

Seattle CSC
909 First Ave., Suite 380
Seattle, WA 98104-3636
(206) 220-6759

Western Area CSC
905 N.E. 11th Ave.
Portland, OR 97232
(503) 230-7597

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 99021
(509) 358-7376

Walla Walla Region
1520 Kelly Place
Walla Walla, WA 99362
(509) 527-6238