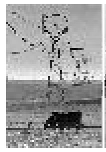
Annual Report for 2001

Bonneville Power Administration



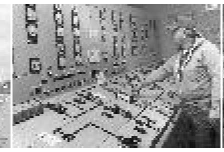


Table of Contents

Photos left to right.

Transmission towers move power across the region.

Boat maps underwater transmission line near Orcas Island.

BPA substation operator.

Regional Transmission Organization meeting.

Chum salmon.

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.

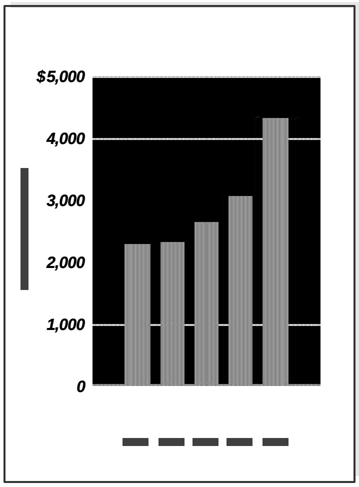
BPA is a self-funding agency that covers its costs by selling its services wholesale to the region's public utilities, municipalities, investor-owned utilities and some large industries. BPA also sells or exchanges power with utilities in Canada and the western United States. Its service area includes 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.

Financial Highlights

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

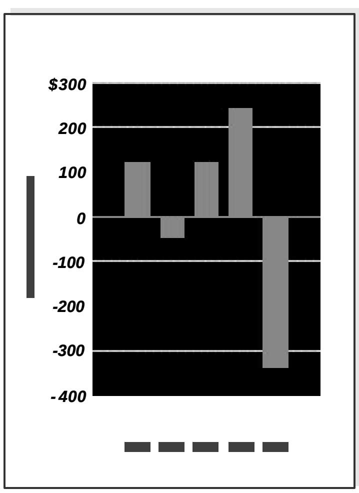
Total Operating Revenues
Millions of dollars



Operating Results
Thousands of dollars

	2001	2000
Revenues	$ 4,230,792	$ 3,040,169
SFAS 133 mark-to-market	47,877	—
Total operating revenues	4,278,669	3,040,169
Total operating expenses	4,115,670	2,464,542
Net operating revenues	162,999	575,627
Net interest expense	331,909	334,650
Net (expenses) revenues before the cumulative effect of SFAS 133	(168,910)	240,977
Cumulative effect of SFAS 133	(168,491)	—
Net (expenses) revenues	***$ (337,401)***	$ 240,977

Net Revenues *(Expenses)*
Millions of dollars



End of Fiscal Year
Thousands of dollars

	2001	2000
Total assets		
(net of accumulated depreciation)	***$ 16,770,530***	$ 16,842,567
Total capitalization and liabilities		
Accumulated net (expenses) revenues	$ (221,151)	$ 132,810
Federal appropriations	4,670,930	4,566,011
Capitalization adjustment	2,259,756	2,328,540
Long-term debt	2,688,542	2,513,200
Nonfederal projects debt	6,171,949	6,408,865
Other	1,200,504	893,141
	$ 16,770,530	$ 16,842,567

Employees
Staff years

	2001	2000
	2,878	2,732

Dear Mr. President:

I am exceptionally proud of the performance of the Bonneville Power Administration and its employees during an extraordinarily challenging year for BPA, the Federal Columbia River Power System and the entire Northwest.

In March, I told BPA's customers and the region that the word that best summed up the way FY 2001 was developing was *extreme*. The water year was extremely low, the West Coast power supply was extremely tight and the cost of power on the market was extremely high.

BPA responded by calling for regional conservation and negotiating power buyback and curtailment agreements with large industrial customers. We also arranged one-for-two power exchanges with California that helped the Northwest and California through their emergencies. These actions helped avoid regional blackouts in the January-to-March period.

The agency was also looking ahead to the FY 2002-2006 rate period that would begin in October 2001. Because of the turmoil in the West Coast energy market, many of BPA's preference customers who had left the agency in the prior rate period signed up to return. We realized in late FY 2000 that BPA had to amend its power rates in the 2002-2006 rate period to reflect the added load and increased power purchase costs.

When we made the decision, we thought the increase might have to be 16 percent. By March, we thought rates might have to go up as much as 60 percent the first year or two of the rate period. As conditions worsened, we were looking at a rate increase of about 250 percent.

At that point, BPA called on the region to take actions to change the future. We couldn't increase the amount of water in the Columbia River Basin, nor could we quickly increase the amount of power available on the market. We could, however, challenge our customers to develop their own power supply or to further reduce their load on the agency through curtailments and conservation.

We extended existing load reduction agreements into the new rate period and arranged power buybacks from more industries and agricultural interests. We created programs to support our customers in capturing conservation — programs that were supposed to begin in October with the new rate period were moved ahead nine months to acquire more savings.

When the deadline for commitments arrived in June, the region had turned in a heroic effort, reducing the load on BPA by 2,277 average megawatts out of a target of 2,400 — that's 95 percent of the target — and reducing the rate increase to 46 percent. Normally we wouldn't celebrate a rate increase of such magnitude, but, given the magnitude of the increase the region was facing, the region was proud of its accomplishment and shared a sense of relief and satisfaction.

I often say that BPA is a public agency devoted to public service in the region. People ask me what that public service is, what it looks like. This year I have a clear example in the effort BPA put into working with the region to reduce the power rate increase, ease the strain on the region's economy and improve reliability.

While the increase was not welcome, the regional conservation and curtailment behind it took enough pressure off the market to help drive down the cost of power on the West Coast and protect the region's economy. Because the rate increase came in at 46 percent rather than 250 percent, the region saved approximately 25,000 jobs. Regional reliability for the coming winter was also substantially enhanced. Credit for these achievements goes to the entire region — industries, utilities and consumers alike.

While we were justifiably jubilant over keeping the lights on during the winter and significantly reducing the anticipated rate increase, the extremes of the water year and the market have extracted a price on BPA and the region. The Columbia River system produced only 52 percent of its normal water volume, the second lowest volume since records have been kept. The resulting reduction in generation forced us to spend about $2.3 billion to purchase power, almost four times the costs we incurred in FY 2000, to augment our power supply to assure reliability and to provide water for threatened and endangered fish.

Even though we were successful at holding the line on internally controllable costs, the final result was a loss of about $337 million. The loss includes an "accounting only" loss of $121 million resulting from adoption of Financial Accounting Standards Board Statement No. 133.

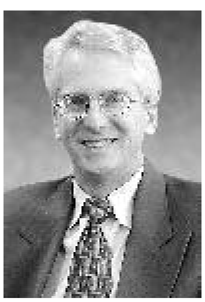
Despite the loss, we ended FY 2001 with reserves of $625 million and with our strong bond rating intact. Also on the plus side, BPA largely avoided making long-term commitments for power purchases back when prices were extraordinarily high. This means the agency has avoided the pitfall that caught many utilities — paying prices far above market for years into the future.

Because of the need to assure reliability, BPA was forced to declare brief power system emergencies during the winter and then, beginning in April, for the duration of the salmon operation year that ended in August. Such declarations allow the agency to operate the hydro system outside the normal National Marine Fisheries Service biological opinion guidelines.

These declarations show a commitment to reliability rather than a lack of commitment to fish recovery. BPA spilled water for migrating salmon and steelhead both in the spring and the summer when water was available. The agency also funded about $9.6 million for projects specifically designed to mitigate for any negative impacts to fish from BPA's emergency operations. That was in addition to approximately $15 million in "high priority" projects the agency funded in May on top of BPA's ongoing fish and wildlife programs. We have also committed to a substantial funding increase for the next five years.

As we look to the future, we're committed to working hard to lower our rates, to provide reliable power and transmission and to support a vigorous fish and wildlife program.

BPA's infrastructure projects are a key focus for the coming year. BPA is planning to increase the output, efficiency and reliability of the generation projects on the Columbia River system; develop a regional energy efficiency strategy; and build up the transmission system to overcome current bottlenecks in order to be able to deliver power from generation plants that will be built over the next few years.



All in all, FY 2001 presented BPA and the region with challenges that no one would willingly have chosen to take on. The combination of drought and unheard of high power prices was formidable. We are proud that BPA and the Northwest met the challenge together.

Cordially,

Stephen J. Wright
Administrator and CEO

Review of 2001

The Bonneville Power Administration and the Pacific Northwest faced two daunting challenges during the 2001 fiscal year. BPA and the utilities, industries and citizens of the region responded to those challenges with unity, determination and imagination.

Mother Nature issued the first challenge with a drought that caught the region by surprise. It wasn't announced by either of the major climatic disruptions of the last few years — no El Niño, no La Niña. But the region received half the normal rain, half the normal snowpack and, as a result, half the normal water in the Federal Columbia River Power System, the source of most of the power the Bonneville Power Administration markets.

The power market presented the second challenge when the spot price for electricity soared to 20 times the previous year's high. This made the effects of the drought worse because the lack of water in the hydro system pushed BPA into the market to buy power to keep the region's lights on during the winter.

Because the agency and the region addressed the issues directly in a unified effort, the year ended well for BPA and the region.

BPA is on solid financial ground. One indicator of that health is that the agency met its annual payment to the U.S. Treasury in full and on time. Treasury repayment is the fundamental measure of BPA's financial health because, by law, BPA must meet all its other financial obligations before it pays the Treasury. Another indicator is that the agency retained its Moody's Aa1 rating with a stable outlook.

The region made it through the winter of 2000-2001 without blackouts and avoided a projected 250 percent electricity rate increase for the beginning of FY 2002. Regional utilities were confident enough in the value of BPA's rates and the agency's financial condition that none of them exercised their option to back out of the new contracts.

Power rates

Long before the hydro system's low water year became an official probability with the first January-July Columbia Basin volume projections in January, BPA was aggressively taking steps to protect the region from the volatile market of FY 2001 and planning for FYs 2002-2006.

In August of 2000, the agency announced to the region and its customers that it was going to have to amend the proposed FY 2002-2006 rates that had been submitted to the Federal Energy Regulatory Commission for approval. BPA's rate staff realized that market rates were rising to heights that no one had anticipated and that the agency's rates had to compensate for the increased cost of purchased power.

The magnitude of the required adjustment became clear with the completion of the Subscription process on Oct. 31, 2000. Subscription was a process through which customers committed to



Photos left to right.

Drought reveals Columbia River sandbars.

Conservation event at Portland's Pioneer Courthouse Square in July.

Hatcheries handled huge salmon returns.

the amount of power they would buy during the 2002-2006 rate period. Because of the skyrocketing market prices for power, customers who had left the agency for the market in previous years turned back to BPA. As a result, the agency was committed to supply about 3,200 average megawatts more power than the Federal Columbia River Power System could produce.

To solve the problem, BPA and its customers spent much of FY 2001 arriving at a mutually acceptable way of integrating the risk of high market prices into BPA's rates while keeping overall rates as low as possible. Customers proposed a flexible approach called the cost recovery adjustment clause (CRAC) under which rates will be adjusted every six months during the rate period to track market costs. Eventually, everyone agreed that this flexible approach called for three different types of CRACs — a load-based CRAC, a finance-based CRAC and a safety net CRAC. The three CRACs are balanced by a dividend distribution clause that would return any overcollections to customers if BPA's adjusted annual net revenues exceed a predetermined figure.

The load-based CRAC is based on the cost of power purchased to meet additional load placed on BPA by customers through the Subscription process. The financial-based CRAC is based on the agency's third quarter projection of accumulated net revenues for the year. The safety net CRAC is based on BPA's probability of making its annual payment to the U.S. Treasury in the coming year.

While the CRAC approach is a dramatic departure from BPA's previous rate strategy, it was supported by customers as necessary to assure BPA's financial viability in the volatile market.

The campaign to reduce FY 2001 power purchases and the October 1 rate increase

From BPA's perspective, the short-term solution to the West Coast power crisis was bringing supply and demand into balance. BPA simultaneously worked on load reduction and power supply increases for FY 2001 and for the first six months of the new rate period.

The region got through the winter because BPA made extensive power purchases, paid the direct service industries (primarily aluminum plants) to reduce their consumption of power, employed emergency operations on the hydro system and arranged one-for-two energy exchanges with California.

Beyond the winter, the region focused on the potential rate increase for the first six months of the FY 2002-2006 rate period beginning on Oct. 1, 2001. Because of the additional load placed on BPA by the Subscription process and the unprecedented cost of power in the market, the region was confronted with the possibility of a load-based CRAC of about 250 percent for the first six months of the new rate period.

BPA asked for all customers to come together to reduce their load on the agency by 5 to 10 percent and for the DSIs to agree to delay resumption of operation for up to the first two years of the new rate period. If all these efforts were successful, BPA explained, the gap between the capacity of the FCRPS and the customer demand could be reduced or eliminated. The more the gap was

reduced, the less the rate hike would be.

The region led by Alcoa Aluminum, Clark Public Utilities and PacifiCorp responded with determination. Through a combination of load curtailment (for example, the deals BPA made with the direct service industries to delay their resumption of operation while BPA reimbursed the companies to cover the salaries and benefits of workers who would otherwise be working) and conservation (using less electricity to produce the same products), load on BPA was reduced sufficiently to bring the rate increase down to 46 percent.

Under most circumstances, it would be hard to imagine the region celebrating such an increase, but the region did. The difference between a 46 percent increase and a 250 percent rate is about 25,000 jobs saved in the Northwest.

The same actions reduced the chance of a major power outage in the Northwest during the winter of 2001-2002 to 12 percent from as high as 27 percent.

BPA and its customers worked closely throughout the effort to hold down the rate increase. One measure of that closeness can be found in the fact that customers remained satisfied with the agency's performance during this difficult time (see Performance Measures on page 21).

New transmission rates

Business was anything but normal for the Transmission Business Line in FY 2001. The TBL concluded its FY 2002-2003 rate case in FY 2000 but that left much to be done so it could implement its new rates and open access tariff with the beginning of the 2002 fiscal year on Oct. 1, 2001. This was no small feat because meeting the open access guidelines set by the Federal Energy Regulatory Commission meant developing and defining products and services that had formerly been bundled with power purchases or didn't exist at all. Consequently, the transmission business became much more complex than it had been previously. New business processes and computer systems had to be developed, tested and implemented for the new fiscal year.

Establishing a regional transmission organization

FERC has urged the development of RTOs as the means to further advance the development of competitive wholesale power

Photos from left to right.

Danger tree crew.

Grand Coulee Dam.

Administrator Steve Wright at a March 2001 press conference on prospective rates.

Wyoming wind power project.

Tower and line construction.

supply markets. In response to FERC's urging, BPA is voluntarily participating along with U.S. investor-owned utilities (Avista Corp., Idaho Power Co., Montana Power Co., PacifiCorp, Portland General Electric Co., Puget Sound Energy Inc. and Sierra Pacific/ Nevada Power Co.) and a Canadian utility (B.C. Hydro & Power Authority) in creating RTO West. BPA is following a set of principles it laid out early in the process that will assure that an RTO based on them will be in the public interest.

The filing utilities forming RTO West achieved their first major milestone when, on April 26, 2001, FERC accepted portions of their Stage One filing from the previous October. That filing outlined the governance and bylaws, scope, configuration, and suspension and liability agreements for the RTO. The utilities will file a status report in December 2001 that responds to FERC direction in its April 26 ruling. That status report will include (1) a framework for formation of a West-wide RTO, (2) resolution of seams issues, (3) a timetable for achieving a West-wide RTO end state and (4) plans for participation in RTO West by Canadian entities.

The report will essentially lay out a vision for the West to create a single market for transmission services through multiple RTOs. The process for this vision is already under way and is being coordinated through a joint committee of the three RTOs (RTO West, California ISO and WestConnect — formerly Desert Star). As it is presently configured, RTO West would cover Washington, Oregon, Idaho and Nevada; most of Montana and Wyoming; a small portion of northern California; and a large portion of southwestern Canada. The filing utilities and regional stakeholders believe this geographic scope provides the best solution for Northwest regional transmission issues. In recent rules and correspondence, FERC has echoed that conclusion.

RTO West is to be a nonprofit independent system operator (operates but does not own transmission facilities) under FERC jurisdiction. Further, some of the utility members (Avista, Montana Power Co., Portland General Electric and Sierra Pacific/Nevada Power) are seeking FERC approval to form a for-profit transmission company called TransConnect to own their transmission facilities but become separate from any merchant activities. TransConnect would then join RTO West as a participating transmission owner according to the same conditions of any other joining utility, authorizing the RTO to operate its transmission facilities.

A comprehensive filing covering substantive matters about how RTO West will work is scheduled to be filed in March 2002.

Conservation and renewable power

Conservation came to the fore in the late fall of 2000 as a technique to help reduce winter loads and prevent outages during a time

Photos left to right.

BPA's "Kids in the Creek" student program.

Burns-Paiute dedication of 6,500 acres in Oregon for wildlife habitat restoration.

Dedication of the Woody Guthrie Circle at Portland headquarters.

of low stream flows and California's inability to send power north as it usually does in the winter.

The emphasis on conservation continued throughout the year as part of the campaign to reduce power purchase costs at BPA during the winter and to keep the Oct. 1 rate increase as low as possible. Because BPA was asking a lot of its customers, it developed programs to help them reach conservation goals ranging from 5 to 10 percent.

In November the agency was already offering its Demand Exchange Program under which it bought back power from large users during periods of high demand. In March, BPA adopted major conservation programs it had designed to be implemented on Oct. 1, 2001, as part of the new contracts for the new rate period.

The Conservation and Renewables Discount option gave utilities and direct service industries a discount on their power purchases from BPA if they created conservation or renewable power programs beyond what they already had in place or scheduled for implementation.

The Conservation Augmentation program allowed customers to use innovative or traditional programs to reduce their load. Customers could design programs to work in individual settings and specify the type and quantity of conservation to be achieved, the delivery system, the cost and the payment method.

As the fiscal year was winding down in September, BPA joined with utilities throughout the region to sponsor the Community Conservation Challenge. The challenge targets communities whose utilities are committed to reducing the load they place on BPA. The challenge encourages utility customers to pledge to switch to energy-efficient appliances, to install compact fluorescent light bulbs, to turn off lights and appliances and to keep temperatures higher in the summer and lower in the winter than in normal years. To motivate people, the program offered those who signed the pledge a chance to win a hybrid gas/electric car.

Other conservation programs BPA designed to support customers include promotion of the ENERGY STAR® compact fluorescent light bulbs and the VendingMi$er™ power control units for vending machines. The VendingMi$er™ powers down the electrical components of vending machines when people are not around, for example, evenings and weekends for most businesses. A motion sensor activates the components when people approach. Demand for the units is strong throughout the Pacific Northwest.

All evidence points to the light bulb market having been transformed over the last half of FY 2001. Coupons from sponsoring utilities for dollars off compact fluorescent bulbs flooded the region and some stores had trouble keeping the bulbs in stock.

BPA ended the fiscal year by sponsoring and hosting the "Conservation or Crisis: A Northwest Choice" conference in Portland. It drew over 500 people from the Northwest to share successes and challenges and to build short- and long-range strategies for energy efficiency programs and technologies. Attendees represented utilities; federal, state and local governments; end users; tribes; and building contractors.

Challenge for PNW energy efficiency strategy

On April 20, BPA received proposals for nearly 850 aMW of wind projects in what was the country's largest request for wind proposals. BPA selected seven projects from that solicitation for further discussion. If all the wind projects BPA is evaluating were developed, BPA could supply about 330 aMW of wind generation within three years. That would be an increase of about 20 percent in the amount of wind generation in the entire country. These new projects will join about 174 megawatts of wind already under contract and

Photos left to right.

BPA-sponsored high school Science Bowl contest.

Senior Vice President Paul Norman tours McNary Dam.

Salmon smolts.

Steve Wright joined Senator Patty Murray in Spokane to give out compact fluorescent light bulbs.

Installing fiber optic cables.

Worker displays the fibers of the cable.

operational, primarily in Wyoming. The new proposals are for projects in Oregon and Washington. The proximity of the new projects will help the agency gather important data on wind productivity and costs, as well as on how to integrate a variable resource into the transmission grid.

Clearly, most of BPA's renewables, both developed and under consideration, are wind projects. The agency also has a limited amount of endorsed hydro and a very small amount of solar currently developed and has committed to acquire the output of a geothermal project.

Green tags and environmentally preferred power

Environmentally preferred power is power that several environmental groups have endorsed as having a low impact on the environment. It is primarily wind, small hydro and solar. BPA sells it at a premium price to raise funds to support its renewables program.

The Bonneville Environmental Fund is an independent nonprofit foundation that develops renewable power and supports watershed restoration. Its Green Tag program, which BPA supports, encourages the development of renewable resources by offering individuals and businesses the opportunity to buy the environmental attributes of renewable generation. Proceeds are used to develop new renewable resources.

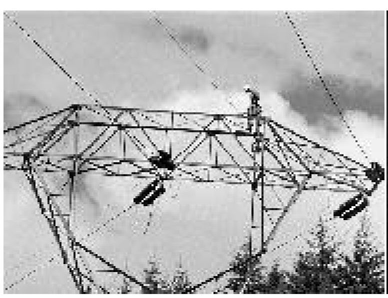
Buying green

BPA doesn't just develop and sell green power; it buys it as well. BPA purchased 460 "shares" of PacifiCorp's Blue Sky wind power for its Portland headquarters. Each share is 100 kilowatt-hours per month. That totals about 5 percent of all the power used in the headquarters building. The agency's "buy green" effort is expanding to all BPA facilities where such products are available.

Fish and wildlife

FY 2001 demonstrated the immense complexity of the fish issues in the Northwest — it was the year of the most abundant returns of anadromous fish since counting began at Bonneville Dam in 1938; it was a year of drought; and it was the year of new biological opinions to aid in long-term recovery of ESA-listed anadromous and resident species and of implementation plans for those opinions.

In December 2000, the National Marine Fisheries Service and the U.S. Fish and Wildlife Service each released new biological opinions on the operation of the FCRPS. The NMFS opinion applies to listed anadromous fish and the USFWS opinion applies to listed resident species.



During much of FY 2001, BPA, the U.S. Army Corps of Engineers and the Bureau of Reclamation (the FCRPS action agencies) developed a plan to describe how the action agencies intend to implement those biological opinions.

The NMFS biological opinion is based on the Final Basinwide Salmon Recovery Strategy the Federal Caucus (BPA, the Corps, Reclamation, NMFS, USFWS, Bureau of Land Management, Environmental Protection Agency and the Bureau of Indian Affairs) released in December 2000. The strategy focuses on the four “Hs” of fish recovery — hydropower, hatcheries, harvest and habitat.

The implementation plan provides a blueprint to coordinate the work of the action agencies across the four Hs. The 2002 plan includes two pieces — a five-year plan describing how the action agencies will implement the biological opinions over the longer term and a one-year implementation plan for FY 2002 identifying specific actions the action agencies will take in FY 2002. In addition, the action agencies will release a progress report detailing their FY 2001 accomplishments. The goal of the implementation plan is to present a disciplined, structured approach designed to ensure clear direction, accountability, and effective and efficient use of resources and benefits. The five-year implementation plan was released for regional review in September 2001. The FY 2002 annual plan was published in November 2001.

The biological opinions acknowledge that FCRPS operations will have to be flexible to reflect variable water conditions. As it became clearer that the 2001 January-July volume would be the second lowest on record, BPA was forced to declare power emergencies and operate outside the biological opinion targets. The criteria the federal agencies developed for declaring emergencies included both power and financial factors. All were based on reliability. The finance criterion was included because all fish operations and vital power operations would be jeopardized if BPA lacked the ability to fund them. That lesson was learned from the California experience in which financial uncertainties resulted in power disruptions and continual crisis.

With constant monitoring of the criteria, river conditions, and spring and summer fish migrations, BPA and its federal agency partners conducted a targeted and limited spring and summer spill program. Using the best real-time data available, the spill was targeted to times when it would be most beneficial to migrating salmon and steelhead. For example, while the spring spill was 15 percent of normal, running 32 days and spilling about 600 megawatt-months of water, NMFS estimates indicated this targeted spill could accomplish a majority of the biological benefit of full spill because of its timing and the locations at which it took place.

As outlined in the biological opinion, the federal agencies relied on maximum transportation of smolts to increase overall survival that would otherwise have been compromised because of the poor in-river conditions associated with the low runoff. In addition, BPA and the other action agencies took immediate and long-term actions to compensate for the variance from the biological opinion measures. The agency sponsored a regionwide call for voluntary conservation with advertisements that featured the governors of Oregon and Washington. BPA also sponsored irrigation programs that saved both the water used in irrigation and the electricity used to drive pumps. Other load reduction and conservation measures described elsewhere also helped lower the demand for energy so more water could be available for fish.

When power was available and affordable, BPA went to the market to increase its ability to spill water for fish and to store water to increase the probability of winter reliability. The one-for-two power exchanges with California that returned more power than was sent south also provided some cushion for the coming winter.

BPA also increased the reward on the northern pikeminnow to accelerate reduction in the number of the salmon and steelhead predators in the Columbia and Snake rivers.

BPA took several steps to improve habitat for fish affected by the drought. In May, the agency committed approximately $15 million to fund a group of high priority projects in addition to the agency's ongoing fish and wildlife programs. The projects (primarily habitat) were to have an immediate benefit for ESA-listed anadromous fish.

In May, the agency sent out a request for proposals for projects to address the effects of the agency's emergency power operations on both ESA-listed and nonlisted fish. The projects were to fall into four categories: increases to tributary flows, tributary habitat passage improvements, tributary diversion screening and fish stock relocation and outplanting. In July, BPA selected for funding a suite of projects recommended by the Independent Scientific Review Panel and the Northwest Power Planning Council. The 17 projects totaled about $9.6 million.

Amid the drought, the Columbia River system saw the largest runs of returning anadromous fish since counting began with the construction of Bonneville Dam. The success of the year's runs can be attributed to good water conditions in the rivers when the fish were juveniles, improved passage at the projects and favorable ocean conditions.

Wildlife

BPA continues to fulfill its obligation to replace the portion of the wildlife habitat lost to the construction of the multipurpose federal dams that is attributable to power use. The program uses the tools of acquisition and rehabilitation. The goal is to provide habitat equivalent to what was lost for the same variety of species. Because BPA is not a land management agency, it usually works through state, federal and tribal fish and wildlife agencies to assure that acquired land is properly managed to benefit wildlife species.

BPA funded two sizeable acquisitions in FY 2001. The agency purchased 9,253 acres along 10 miles of the John Day River in Oregon, the second-largest undammed river in the United States and the only Columbia River subbasin that supports totally wild populations of salmon and steelhead. In addition, the purchased ranch potentially supplies habitat for at least 36 animal and plant species that are listed as sensitive, threatened or endangered, including bald eagles, spring chinook, summer steelhead and

Pacific lamprey. The land will be owned and managed by the Confederated Tribes of the Warm Springs Reservation.

BPA also funded the Burns-Paiute Tribe's purchase of 6,500 acres of richly diverse land on the Malheur River in northeastern Oregon. The land was formerly part of the Malheur Reservation and the tribe is interested in re-establishing cultural use of the land as well as in restoring and enhancing habitat that is critical to resident and migrating wildlife. The land is home to two species listed as threatened or endangered (bald eagles and bull trout) and several species of concern. This habitat recovery will help both fish and wildlife.

In addition to the large acquisitions, BPA also funded the purchase of two parcels of land west of Portland, Ore., in the Tualatin River flood plain. The parcels will be combined with others to create a 3,000-acre refuge that will be managed by the U.S. Fish and Wildlife Service for fish and wildlife values. These purchases are part of the effort to mitigate for habitat lost to the construction of federal dams in the Willamette River watershed and will help protect many imperiled wetland species.

BPA also purchased 46 acres on Salmon Creek in the Okanogan Valley of northeastern Washington to protect the watershed and provide habitat for deer, elk and beaver. That land will be managed by the Colville Tribe. In northwestern Montana, BPA purchased 440 acres of land that are critical to the success of the gray wolf population. The land will also benefit bald eagles and the Ute ladies' tress orchid, a threatened species. The Confederated Salish and Kootenai Tribes will manage the land.

Tribal relations

The current BPA Tribal Policy has guided the agency in maintaining positive working relationships and close cooperation with the tribes since 1996. In FY 2001 the design of RTO West, transmission rights-of-way, cultural resource preservation, fish and wildlife management and BPA's partnership with the Affiliated Tribes of Northwest Indians/ Economic Development Corporation (ATNI/EDC) were major areas of cooperation.

Early in FY 2001, several tribes asked for consultations about the development of a proposed RTO. Many of the regional tribes were concerned about their relationships with a new nonfederal entity if an RTO were established. In response, BPA assisted (through its partnership with ATNI/EDC) in hiring a tribal consultant to provide policy analysis of the design of the RTO and to ensure a continuing role for the tribes in the RTO

Photos left to right.

Wind construction at Condon, Ore.

Substation control panel.

Recruiting new employees.

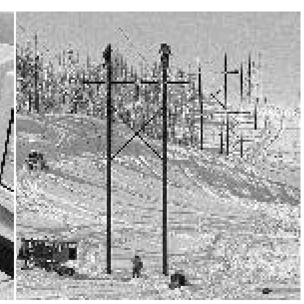
formation. BPA and other filing utilities will retain ownership of their individual transmission lines and the responsibility for maintaining them. This assures that BPA's treaty and trust obligations to the tribes regarding federal transmission rights-of-way on and off reservations will remain unchanged.

Over the past year, BPA has initiated environmental analysis work on several proposed transmission projects throughout the region. Early information sharing about potential routes has resulted in opportunities for many tribes to contract with BPA to conduct cultural resource surveys in areas of tribal importance. Good examples include the ethnobotany surveys conducted by the Snoqualmie and Muckleshoot tribes along the proposed Kangley-Echo Lake transmission route in western Washington. Additionally, the Yakama and Umatilla tribes participated in the archeological investigation and oral history studies of the preferred alternative for the Starbuck transmission project in eastern Washington. The Nez Perce and Confederated Colville tribes also provided oral history studies for this project.

The Samish and Swinomish tribes in Washington honored BPA for its role in cultural preservation during a ceremony in July. The ceremony paid respect to the disturbed spirits of ancestors whose remains had been found during an archeological survey. BPA conducted the survey in preparation for stringing an underwater cable to the San Juan Islands. When the remains were found, BPA stopped work, notified the tribes of the find and invited them to the site. BPA and the tribes then negotiated a memorandum of agreement to guide remaining investigation of the proposed cable route.

The Federal Columbia River Power System cultural resource program managers from the Corps, Reclamation, BPA and the 13 Columbia Basin tribes identified and worked together through the many river operations concerns caused by the power emergencies of this past spring and early summer. When Grand Coulee and other upriver storage reservoirs were drawn down for the emergencies, BPA provided additional funding for tribal archeologists and law enforcement staff to monitor and protect exposed graves and other cultural sites.

The BPA-ATNI/EDC partnership continues to be a valuable asset in increasing tribal understanding of energy issues through dissemination of educational information and specific power and transmission technical and policy issues of tribal interest. In FY 2001, the ATNI/EDC tribal energy coordinator and BPA staff continued the past three years' effort to serve 54 ATNI member tribes by distributing information and by making visits to promote BPA business opportunities, energy efficiency and energy-related technical and policy issues. The ATNI/EDC staff assisted BPA in conducting two energy



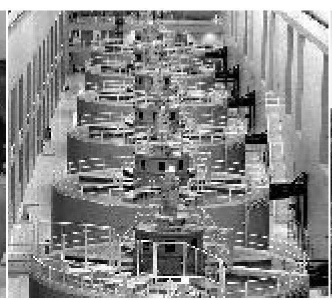
workshops and two facilitated consensus-building leader-to-leader workshops. As tribes increasingly become utility industry players, having a positive working relationship and being able to reach common ground on challenging issues will allow BPA and tribes to be of enormous assistance to one another.

Such assistance is seen in the way the Cow Creek Band of the

Umpqua Tribe of Indians in Oregon signed a Subscription contract with BPA as part of its plan to create a utility. BPA also entered into talks with the Yakama Indian Nation in Washington about creation of a utility and is talking to the Blackfeet Tribe in Montana about a wind generation project.

International

BPA's role, along with the Corps of Engineers, as the "entity" that implements the Columbia River Treaty with Canada had added importance in FY 2001. Canadian reservoirs make up 37 percent of the storage in the Columbia/Snake river system. Because of its long-standing relationship with Canada, BPA was able to negotiate three million acre-feet of storage in the Canadian reservoirs in addition to what is called for in the treaty, making a significant difference in the amount of water the FCRPS has available going into the winter of FY 2002 and improving system reliability.



Photos left to right.

Power Business Line dipatcher.

Winter maintenance crew.

Compact fluorescent bulb coupons given to BPA employees.

Hydro turbines.

Irrigation.

High-performing organization

BPA understands that, in order to deliver on its responsibilities to the region, it needs to hire, develop and retain the best talent available and operate in a way that results in a high-performing organization. This has been the foundation of BPA's Strategic Business Objectives since 1993. Measurable indicators of the agency's progress in this area provide strong evidence of continued improvements.

FY 2001 was the second year in which the agency used measurable indicators of its progress toward becoming a high-performing organization. The employee survey uses questions developed by the agency and by the Great Place to Work® Institute to evaluate the agency's progress in five areas — trust, respect, fairness, pride and camaraderie.

Last year, BPA emphasized developing employees and recruiting new talent for a somewhat expanding workforce. The structural, technological and economic changes occurring in the electric utility industry demand that BPA's workforce develop the knowledge and understanding of these changes to continue to be at the forefront of the industry. As a consequence, BPA significantly increased training and development opportunities. BPA also hired more new employees than it has in about a decade to compensate for several years of downsizing and in anticipation of a significant number of retirements from its aging workforce over the coming years.

The long term

The long-term solution to the West Coast power crisis will come from increasing generation supply and from building the infrastructure to better deliver both natural gas to generators and power from generators to customers.

Despite its focus on the immediate crisis, BPA began laying the groundwork for the agency's contribution to long-term energy stability in the region through preliminary work on its "infrastructure" project.

Overcoming transmission gridlock

While most eyes were focused on power generation — how much the region was short on generation and how much generation was proposed — BPA's Transmission Business Line was calling the region's attention to the state of the West Coast power grid. All 11 Western states, as well as the provinces of British Columbia and Alberta, are connected by a network of transmission lines collectively known as the transmission grid.

The grid has been a positive influence on the region for decades. It allows excess generation in the Northwest, for example, to flow to California and the desert Southwest in the summer when residents of those areas use air conditioning and power demands are high. The grid also allows excess generation in California and the Southwest to flow north in the winter when Northwest residents use heat and demand is high.

This interconnectedness allows each area to build fewer power plants than it would need if it had to support its demands on its own. This has been a great economic benefit.

That same grid allowed the California energy crisis to flow to the entire West. When California became short of power in the winter of 2000-2001, it exacerbated the usual and expected winter power shortage in the

Photos left to right.

The Conservation or Crisis conference.

Honda Insight hybrid car.

Tranmission Business Line dispatchers.

Northwest. Instead of supplying power to the Northwest, California competed with the Northwest for the little power available on the market. Prices soared.

While more generation seems to be the answer to all these problems, it became clear to agency engineers that more generation can compound the problem. There simply isn't enough transmission capacity to carry all the new generation from the generation sites to the people who need the power.

Further, the power emergency called attention to existing "constrained paths," or transmission bottlenecks, that are a problem even without additional generation. For several reasons, including higher national reliability standards, certain transmission paths are unable to carry the power generated on one side of the bottleneck to the demand on the other side. Some of the more significant constrained paths prevent power from the Colstrip coal plants in eastern Montana from reaching Washington's population centers and prevent power from the McNary Dam area on the Columbia from reaching Portland.

Proposed new generation tends to cluster along natural gas pipelines on the eastern side of Washington and Oregon, away from the population centers along the I-5 interstate highway corridor. This will exacerbate the existing constraints.

The Transmission Business Line created the internal Strategic Infrastructure Response Team in March 2001 to address the issues of constrained paths, integration of new generation and reliability. The BPA team identified nine projects as the most crucial for early development and an additional 11 projects for later construction. A number of BPA customers requested an opportunity to review the project proposals for cost effectiveness and reliability. A committee of representatives from private and public power customers met and reviewed the proposals. The committee issued a report unanimously supporting the first nine projects. The committee will review additional proposals in future years.

More power for the future

Even before the West Coast power shortage became evident, BPA took a thorough look at the state of the Federal Columbia River Power System. BPA, the U.S. Army Corps of Engineers and the Bureau of Reclamation already had in place an asset management plan to upgrade the projects the Corps and the Bureau own and operate on the Columbia and Snake rivers.

The plan was made possible when the agencies arranged for BPA to provide "direct funding" of the operation and maintenance budgets for the dams. Previously, maintenance was approved through the congressional appropriations process. During that period, the availability of the generating units fell well below industry standards of 90 percent.

The asset management plan is budgeted at $776 million in capital expenditures for generation efficiencies, hydro optimization and reliability improvements over the next 10 years.

The re-evaluation of the projects identified another $496 million in capital expenditures over 10 years that could increase the output of the FCRPS by 117 average megawatts while increasing reliability and efficiency. The goal is to increase generation availability to 95 percent while increasing generation capacity.

BPA's responsibilities to the Northwest require that it do its best to maximize the FCRPS output. Under conditions such as those in FY 2001, the FCRPS cannot produce enough power to meet BPA's customer load. Additional cost-effective FCRPS generation capacity will help reduce BPA's power shortage and the costs associated with buying power on the market.

Conservation capital projects

Conservation is also part of BPA's infrastructure project as an extension of the conservation augmentation approach. Any cost-effective conservation that can be acquired reduces the need to build or buy more power. Hence, some investments in conservation can be considered capital investments and a part of BPA's infrastructure project. In its last rate proceeding, BPA included testimony and revenue requirements to capitalize new conservation programs. In its 1998 Power Plan, the Northwest Power Planning Council determined that BPA could acquire 470 aMW of conservation through 2011. About 225 aMW of that would come from additional capital investments.

These infrastructure projects can make a substantial contribution to the long-term power solution for the region. The agency is also working in the "Energy Web" and distributed power arenas through its support of fuel cells and photovoltaics, technologies that reduce the need for transmission and large generation plants.

BPA is planning for the infrastructure projects and is evaluating sources of financing for them because the agency is serious about its responsibility to provide inexpensive and reliable power to the Northwest in the short term and in the long term. That is part of its public responsibility, a responsibility that has become more important as the incomplete deregulation and restructuring of energy generation and transmission has diffused and obscured the responsibility for energy planning.

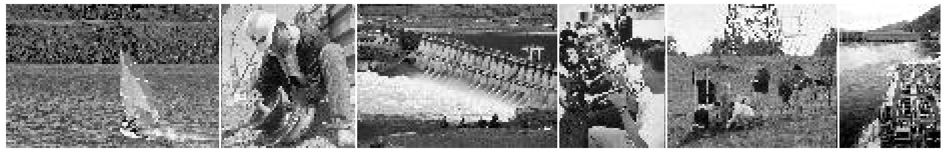
BPA wants to help the region create an energy conservation strategy that is competitively neutral among utilities and that provides a sustained level of conservation. The goal is to get off the market-driven roller coaster in which support for conservation is strong when power prices are high and weak when prices are low.

FY 2001 was a challenging year. Even though the agency had to respond to the immediate crisis posed by the drought and the market spike, it didn't waiver from the priorities the management team set at the beginning of the year. Adherence to those priorities prepares the agency to meet the long-term challenges.

This list of priorities is long and comprehensive, as it should be for an agency so important to the region. During FY 2001, the agency concluded the power rate case on time, successfully augmented the Federal Columbia River Power System to meet contractual obligations for the new rate period, developed a plan to implement the biological opinions that determine how the FCRPS should operate to protect threatened and endangered species, joined with the region's investor-owned utilities to advance the regional transmission organization, resolved the issues surrounding the survival of the direct service industries in the short term and will be addressing the long term, implemented a winter readiness plan, prepared for federal legislation to restructure the power industry and maintained our financial solvency.

BPA accomplished all this while contributing significantly to the solution of the region's short-term energy crisis.

This makes for a year of exceptional accomplishment under very trying conditions. BPA is well positioned to continue to make substantial contributions to the region's well being.



Performance Measures

Photos left to right.

Wind surfing.

Lineman and insulator.

The Dalles Dam.

BPA volunteer band plays at Pioneer Courthouse Square.

BPA employees plant trees on the Ross Complex in Vancouver, Wash., for Earth Day.

Barge carries salmon smolts.

Each year since 1995, BPA has selected a set of measurable goals that the agency as a whole is responsible for achieving. These targets act as an indicator of overall agency success and determine the agencywide portion of the employee recognition program. In FY 2001, the agency met 4.5 of 6.0 targets. Each target has a range of acceptable scores. Hitting the highest end of the range provides 100 percent credit; hitting the lowest acceptable end produces a 50 percent credit. Results in between are prorated. The idea is to provide incentives for exceptionally high achievement without punishing good achievement.

Finance

The agency met its very important goal of controlling internally managed costs to fall within the range of $1,009 million to $979 million. BPA also made its payment to the U.S. Treasury on time and in full although it failed to produce net revenues in the range from $11 million to $103 million.

Stakeholders

The goal for the composite agency customer satisfaction index was to be in the range from 7.2 to 7.6. The result was 7.4.

The agency met the lowest end of the range on the tribal government satisfaction index with a score of 6.1. The range was from 6.1 to 6.4. The agency did not meet the composite state/federal entities and constituent satisfaction index goal of falling within the range from 7.2 to 7.5. The result was 7.0.

Internal systems and processes

The target for high system reliability/sufficiency had two parts. Transmission was to have its outage frequency and duration result in no control chart violations while Power was to have no involuntary curtailments of firm load due to inadequate power supply. Both were met.

The safety goal was for recordable lost-time injuries to be in the range from 1.7 to 1.2 per 200,000 hours worked and for no fatal injuries to occur to BPA or contract employees working on BPA facilities. Both goals were reached. The rate of injury was 1.1 per 200,000 hours worked, which was down significantly from the 1.4 result in FY 2000.

Financial Section

Photos left to right.

Counting white sturgeon in upper basin.

Steve Wright joined Washington Govenor Gary Locke and Seattle City Light officials to promote conservation at SAFECO Field in Seattle.

Celilo Converter Station mercury arc valves are being replaced by state-of-the-art thyristors.

BPA booth at salmon festival.

Forest fires threatened transmission lines in 2001.

Results of Operations

2001 Compared to 2000

The 2001 operating revenues were $4,278 million, an increase of $1,238 million from the previous year. Despite a very low water year, revenue from power sales were up primarily because market prices for discretionary power sales increased to 101 mills from the previous year average of 29 mills. U.S. Treasury Credits for Fish increased over 10 times from 2000 to 2001. Due to the drought conditions and high market prices for purchased power the 4(H)10c revenue credit increased to $354 million. The credit computation is subject to an annual true-up. Furthermore, as a result of the market conditions BPA accessed the Fish Cost Contingency Fund for the first time in history. The $325 million fund is for excess payments electric ratepayers have made for salmon recovery in prior years. BPA accessed the fund for an additional $247 million in credits, leaving the fund balance at $78 million. Net expenses were $337 million in 2001, a decrease of $578 million from 2000 net revenues and the largest net expenses in BPA's history.

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.

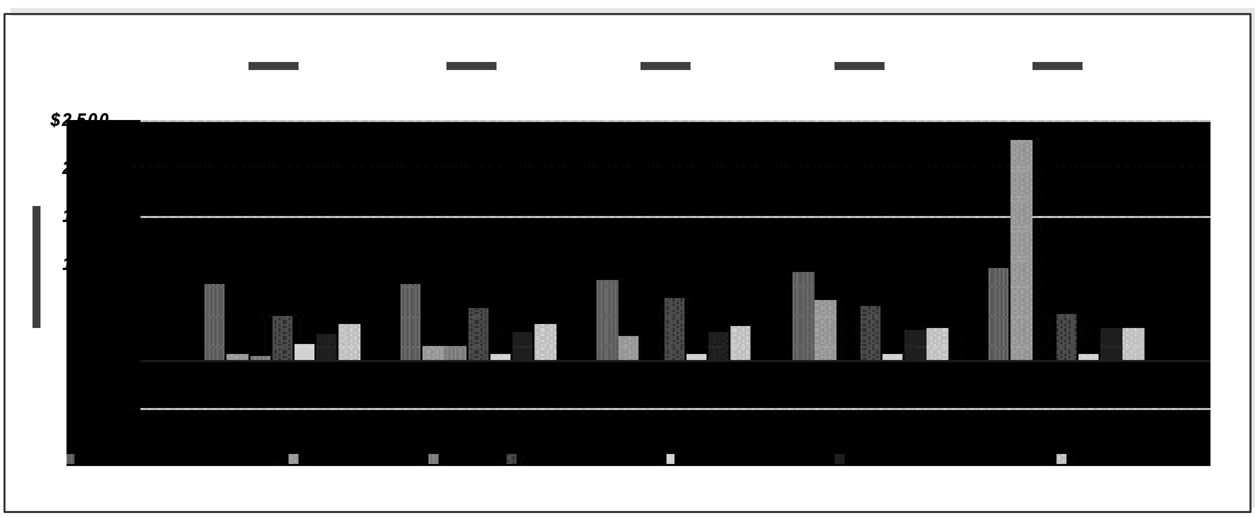
Expenses

Total FCRPS operating and net interest expenses increased by $1,648 million in 2001 to $4,448 million, an increase of 59 percent over the previous year. 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 expenses were $2,496 million, an increase of 6 percent compared to 1998. Operating expenses have increased primarily because of an increase in purchased power expense.

Operation and maintenance costs for the FCRPS rose by $41 million in 2001, an increase of 5 percent. Higher operations and maintenance expenses for BPA and the Columbia Generating Station nuclear project were the primary cause for the increase. Operation and maintenance costs 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 $1,659 million, or 262 percent, to $2,292 million in 2001. Megawatt-hours purchased increased 137 percent in 2001 from 2000 levels. The average cost of purchased power increased from 57 mills in 2000 to 90 mills in 2001. Purchased power costs increased by $368 million, or 139 percent, to $633 million

Expenses by Category



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 2001, debt service on nonfederal projects was $477 million, a decrease of $83 million, or 15 percent, compared to 2000. Selective redemption of bonds at Energy Northwest allowed the free up of bond reserves that were used to reduce current debt service. In 2000, debt service on nonfederal projects was $561 million, a decrease of $90 million, or 14 percent, compared to 1999, primarily because funds were released from certain debt service reserve accounts. In 1999 debt service on nonfederal projects increased by $106 million, or 19 percent, from $545 million in 1998.

Net residential exchange expense was $68 million in 2001. Additional settlement payments account for the $5 million increase from the prior year. 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 most of its electric utility customers. These contracts result in payments to the utilities, which must be passed through to its qualified residential and irrigation loads, if a utility's average system cost exceeded BPA's priority firm power rate.

Subsequently, contract termination agreements were signed by all actively exchanging Pacific Northwest utilities except The Montana Power Co. (which had been receiving no benefits), whereby payments were made by BPA to settle the utilities' and BPA's rights and obligations under the residential exchange program through June 30, 2001, and in some cases, through June 30, 2011. In Oct. 2000, BPA's investor owned utility (IOU) customers signed settlement agreements for settlement of the period running from July 1, 2001 through Sept. 30, 2011. These agreements provide for both sales of power and cash payments to the IOUs. Net residential exchange expense was $64 million in 2000, the same as 1999 and 1998.

Federal projects depreciation was $323 million in 2001, nearly the same as the prior year. 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 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 $332 million in 2001, down $3 million from the prior year. Net interest expense was $335 million in 2000, a decrease of $21 million from the previous year. The decrease was a result of higher interest income due to higher cash balances during the year and lower interest rates on bonds. 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

At Sept. 30, 2001, BPA's year-end financial reserves were $625 million — consisting of $586 million cash and $39 million for deferred borrowing authority. At Sept. 30, 2000, BPA's year-end financial reserves 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 $729 million to the U.S. Treasury in 2001, making it the eighteenth consecutive year in which BPA has made its payment on time and in full. The payment consisted of $253 million for principal, $464 million for interest and $12 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 2000, 1999 and 1998 were $732 million, $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

Through Sept. 30, 2001, BPA's rates remained the same as the previous four years 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. These rates were designed to maximize BPA revenues in an anticipated increasingly competitive wholesale power market. Rates increased 46 percent on Oct. 1, 2001. Based on the unprecedented market volatility in the power industry and severe drought conditions occurring during the year BPA management had anticipated the rate increase might be over 200 percent. The agency asked Northwest aluminum plants and other energy-intensive industries to cut back on operations, and compensated their laid-off employees. Combined, customers reduced load by roughly 2,000 average megawatts or about 10 percent of the region's total electrical usage, enabling the agency to put in place the 46 percent rate increase rather than the anticipated higher rate increase.

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 2001, BPA's debt in this category totaled $2,688 million — an increase of $175 million from the prior year. Long-term debt of $2,513 million at the end of 2000 was 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 2001 was $4.7 billion.

In 1997, the U.S. Treasury approved BPA's implementation of the BPA Appropriations Refinancing 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 $6.2 billion to nonfederal sources for financing three Energy Northwest nuclear projects and several smaller generation and conservation investments. BPA backs bonds issued by others in the capital markets to finance these projects.

Three rating agencies continued to maintain high credit ratings for BPA-backed Energy Northwest bonds in 2001. Moody's Investors Service maintained a rating of Aa1, the second highest possible rating. Fitch IBCA affirmed their AA rating citing increased flexibility to adjust power rates as a longer-term benefit for BPA in its ability to meet future operating and financial requirements. Standard & Poor's affirmed their AA- rating on the BPA-backed bonds and revised the outlook from positive to stable reflecting their overall concern regarding the escalation of wholesale power prices in Western markets and possible economic implications in markets served by BPA.

Market Risk

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

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

BPA measures the market price risk in its portfolio on a daily, weekly, and monthly basis using 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 buys and sells. 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. Unlike many of its industry counterparts, BPA is primarily selling surplus inventory rather than focusing on trading activity. Therefore, the tests critical to trading organizations are considered less important than regular and rigorous testing for hydro supply conditions. Experienced business and risk managers use the results of the hydro supply scenario analyses and the market price risk measures in conjunction with their professional judgment to capture additional market-related risks, including credit and event risk. In response to market price risk, futures, swaps and options may be used to alter BPA's exposure to price fluctuations.

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

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

Bonneville Enterprise System

In August 2000, Bonneville 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 system covers more than a replacement of Bonneville's old financial systems. The BSP is expected to reduce administrative costs and to save information technology costs compared to the previous systems. Bonneville staff spent two years developing, testing and planning the conversion to the BSP information system. The implementation has been a success with ongoing testing and system upgrades expected over the next several years. In late 2001 the BSP was renamed the Bonneville Enterprise System to reflect the successful installation of the new system.

Selected Quarterly Information *(unaudited)*

3 months ended — Thousands of dollars

	Dec 31	March 31	June 30	Sept 30	Totals
2001					
Revenues	$ 788,313	$ 1,322,994	$ 851,539	$ 1,267,946	$ 4,230,792
SFAS 133 mark-to-market	(292,720)	345,035	216,270	(220,708)	47,877
Operating revenues	495,593	1,668,029	1,067,809	1,047,238	4,278,669
Operating expenses	887,606	1,177,963	845,332	1,204,769	4,115,670
Net interest expenses	81,459	82,841	82,345	85,264	331,909
Net (expenses) revenues before cumulative effect of SFAS 133	(473,472)	407,225	140,132	(243,795)	(168,910)
Cumulative effect of SFAS 133	(168,491)	—	—	—	(168,491)
Net (expenses) revenues	***$ (641,963)***	***$ 407,225***	***$ 140,132***	***$ (243,795)***	***$ (337,401)***
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***

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.

BALANCE SHEETS

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

Assets

	2001	2000
Utility Plant (Notes 1 and 3)		
Completed plant	$ 11,249,158	$ 11,105,332
Accumulated depreciation	(3,817,309)	(3,583,557)
	7,431,849	7,521,775
Construction work in progress	913,670	636,000
Net utility plant	8,345,519	8,157,775
Nonfederal Projects (Note 4)		
Conservation	50,189	52,497
Hydro	170,730	204,625
Nuclear	2,116,473	2,231,874
Terminated hydro facilities	30,245	30,905
Terminated nuclear facilities	3,804,312	3,888,964
Total nonfederal projects	6,171,949	6,408,865
Trojan Decommissioning Cost (Note 6)	69,221	78,307
Conservation, net of accumulated amortization of $769,221 in 2001 and $708,666 in 2000 (Notes 1 and 2)	444,021	504,504
Fish and Wildlife, net of accumulated amortization of $110,954 in 2001 and $105,138 in 2000 (Notes 1 and 2)	146,354	145,586
Current Assets		
Cash	667,306	848,447
Accounts receivable	381,899	238,179
Accrued unbilled revenues	5,906	118,343
Materials and supplies, at average cost	85,222	64,292
Prepaid expenses	187,149	85,895
Total current assets	1,327,482	1,355,156
Other Assets	265,984	192,374
	$ 16,770,530	***$ 16,842,567***

The accompanying notes are an integral part of these statements.

Capitalization and Liabilities

	2001	2000
Accumulated Net (Expenses) Revenues (Note 1)	$ (221,151)	$ 132,810
Federal Appropriations (Note 3)	4,647,017	4,499,743
Capitalization Adjustment (Note 3)	2,259,756	2,328,540
Long-Term Debt (Note 2)	2,582,542	2,513,200
Nonfederal Projects Debt (Note 4)	5,954,490	6,053,027
Trojan Decommissioning Reserve (Note 6)	57,221	65,707
Total capitalization and long-term liabilities	15,279,875	15,593,027
Commitments and Contingencies (Notes 6 and 7)		
Current Liabilities		
Current portion of federal appropriations	23,913	66,268
Current portion of long-term debt	106,000	—
Current portion of nonfederal projects debt	217,459	355,838
Current portion of Trojan decommissioning reserve	12,000	12,600
Accounts payable and other current liabilities	510,957	372,270
Total current liabilities	870,329	806,976
Deferred Credits (Note 1)	620,326	442,564
	$ 16,770,530	***$ 16,842,567***

STATEMENTS OF REVENUES AND EXPENSES

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

	2001	**2000**	**1999**
Operating Revenues			
Sales	$ 3,563,182	$ 2,903,735	$ 2,555,550
SFAS 133 mark-to-market	47,877	—	—
Miscellaneous Revenues	66,902	76,434	36,983
U.S. Treasury Credits for Fish	600,708	60,000	26,346
Total operating revenues	4,278,669	3,040,169	2,618,879
Operating Expenses			
Operations and maintenance	955,098	913,846	850,741
Purchased power	2,291,961	633,142	265,304
Tenaska (Note 7)	—	(26,817)	—
Nonfederal projects (Note 4)	477,215	560,836	651,093
Residential exchange (Note 5)	68,082	63,593	63,619
Federal projects depreciation	323,314	319,942	309,183
Total operating expenses	4,115,670	2,464,542	2,139,940
Net operating revenues	162,999	575,627	478,939
Interest Expense			
Interest on federal investment:			
Appropriated funds (Note 3)	248,429	248,352	249,156
Long-term debt (Note 2)	129,159	115,052	130,916
Allowance for funds used during construction	(45,679)	(28,754)	(24,419)
Net interest expense	331,909	334,650	355,653
Net (expenses) revenues before cumulative effect of SFAS 133	(168,910)	240,977	123,286
Cumulative effect of SFAS 133	(168,491)	—	—
Net (Expenses) Revenues	(337,401)	240,977	123,286
Accumulated net (expenses) revenues, Oct. 1	132,810	(108,167)	(231,453)
Irrigation Assistance	(16,560)	—	—
Accumulated net (expenses) revenues, Sept. 30	***$ (221,151)***	***$ 132,810***	***$ (108,167)***

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	Federal Appropriations	Long-Term Debt	Nonfederal Project Debt	Other	Total
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***
Increase (decrease) in federal appropriations:						
Construction	—	230,388	—	—	—	230,388
Repayment of federal appropriations:						
Construction	—	(125,469)	—	—	—	(125,469)
Capitalization adjustment amortization	—	—	—	—	(68,784)	(68,784)
Irrigation Assistance	(16,560)	—	—	—	—	(16,560)
Increase in long-term debt	—	—	260,000	—	—	260,000
Repayment of long-term debt	—	—	(84,658)	—	—	(84,658)
Net decrease in nonfederal projects debt	—	—	—	(60,658)	—	(60,658)
Repayment of nonfederal projects debt	—	—	—	(176,258)	—	(176,258)
Trojan decommissioning reserve	—	—	—	—	(9,086)	(9,086)
Net expenses	(337,401)	—	—	—	—	(337,401)
Balance at Sept. 30, 2001	***$ (221,151)***	***$ 4,670,930***	***$ 2,688,542***	***$ 6,171,949***	***$ 2,328,977***	***$ 15,639,247***

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

	2001	2000	1999
Cash from Operating Activities			
Net (expenses) revenues	$ (337,401)	$ 240,977	$ 123,286
Expenses (income) not requiring cash:			
Depreciation	247,247	242,673	233,279
Amortization of conservation and fish and wildlife	76,067	77,269	75,904
Amortization of nonfederal projects	176,258	323,619	145,185
Amortization of capitalization adjustment	(68,784)	(67,474)	(64,886)
AFUDC	(45,679)	(28,754)	(24,419)
(Increase) decrease in:			
Receivables and unbilled revenues	(31,283)	(155,444)	(13,367)
Materials and supplies	(20,930)	6,785	3,630
Prepaid expenses	(101,254)	(3,200)	(1,105)
Increase (decrease) in:			
Accounts payable	138,687	100,699	(43,611)
Other	114,060	8,437	(12,769)
Cash provided by operating activities	146,988	745,587	421,127
Cash from Investment Activities			
Investment in:			
Utility plant	(399,220)	(310,165)	(215,155)
Conservation	141	—	(12,484)
Fish and wildlife	(16,493)	(13,898)	(14,748)
Cash used for investment activities	(415,572)	(324,063)	(242,387)
Cash from Borrowing and Appropriations			
Increase in federal appropriations:			
Operations and maintenance	—	—	160,037
Construction	230,388	129,953	93,364
Repayment of federal appropriations:			
Operations and maintenance	—	—	(160,037)
Construction	(125,469)	(62,425)	(40,984)
Irrigation assistance	(16,560)	—	—
Increase in long-term debt	260,000	294,300	192,400
Repayment of long-term debt	(84,658)	(227,500)	(150,000)
Refinance of long-term debt	—	(68,800)	(26,200)
Payment of nonfederal debt	(176,258)	(323,619)	(145,185)
Cash used for borrowing and appropriations	87,443	(258,091)	(76,605)
Increase in cash	(181,141)	163,433	102,135
Beginning cash balance	848,447	685,014	582,879
Ending cash balance	***$ 667,306***	***$ 848,447***	***$ 685,014***

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 2000 combined financial statements from amounts previously reported to conform to the presentation used in fiscal year 2001. 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.

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

	2001	2000
Nonfederal projects:		
Conservation	$ 50,189	$ 52,497
Terminated nuclear facilities	3,804,312	3,888,964
Terminated hydro facilities	30,245	30,905
Trojan decommissioning cost	69,221	78,307
Conservation	444,021	504,504
Fish and wildlife	146,354	145,586
Additional retirement contributions	68,100	53,000
Total	***$ 4,612,442***	***$ 4,753,763***

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

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

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

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

The SFAS 71 assets of $4.6 billion, shown in the table on page 33, reflect a decrease of $141 million from the prior year. Amortization of these costs aggregating $259 million in fiscal 2001, $276 million in 2000 and $242 million in fiscal 1999 is reflected in the Statements of Revenues and Expenses.

Revenues and Net Revenues

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

AFUDC capitalization rates are stipulated in the congressional acts authorizing construction for certain generating projects (2.5 percent to 6.6 percent in 2001, 2.5 percent to 6.7 percent in 2000 and 2.5 percent to 6.8 percent in 1999). Capitalization rates for other construction approximate the cost of borrowing from the U.S. Treasury (6.5 percent in 2001, 6.6 percent in 2000 and 6.7 percent in 1999).

Depreciation and Amortization

Depreciation of original cost and estimated cost to retire utility plant is computed on the straight-line method based on estimated service lives of the various classes of property, which average 40 years for transmission plant and 75 years for generation plant. Amortization of capitalized conservation and fish and wildlife costs is computed on the straight-line method based on estimated service lives, which are 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 projected over a period of years as shown in the table on page 29. The payments, when made, will be directly to the U.S. Treasury.

BPA paid approximately $8.0 million, $6.0 million and $4.1 million to the U.S. Treasury during fiscal 2001, 2000 and 1999, respectively. These amounts were recorded as expense when paid. BPA has accrued for $68.1 million as of Sept. 30, 2001, which represents the additional deferred contribution for fiscal 1998, 1999, 2000 and 2001. 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, 2001, BPA has scheduled additional payments totaling $192 million as follows:

Scheduled Additional CSRS Contributions
Millions of dollars

Scheduled Contributions		
2002	$	55.2
2003		35.1
2004		30.9
2005		26.5
2006		23.2
2007		21.1
Total	*$*	*192.0*

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 $464 million in 2001, $403 million in 2000 and $421 million in 1999.

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 $61 million in 2001, $40 million in 2000 and $112 million in 1999.

Concentrations of Credit Risks

General Credit Risk

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

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

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

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

Credit Risk from California

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

Bonneville entered into certain power sales through the Cal-PX for which Bonneville has not yet been paid. In addition Bonneville sold power and related services to the

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

Deferred Credits

Deferred credits consist of $131.3 million paid to BPA from participants under the 3rd AC intertie capacity agreement, $93.8 million in load diversification fees and other settlement payments for long-term agreements paid to BPA from various customers, $68.1 million in deferred CSRS contributions of which $31.3 million is included with accounts payable and other current liabilities, $113.5 million in advances from customers for projects which BPA is constructing on their behalf, $39.9 million in unearned option premium revenue, $120.6 million current fair market value of purchased and written options and certain trading physical forward sales and purchases, $72.9 million for Golden Northwest Aluminum (GNA) remarketing, $10.6 million leasing fees for fiber optic cable, and $.9 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 ended Sept. 30, 2001, while other settlement agreements extend over varying periods through 2019). Advances on projects BPA constructs for customers are either applied against expenditure during the construction of the assets if the customer retains title to the assets, or if BPA retains title, are recorded to revenue over the related useful lives of the assets. GNA remarketing is an account related to GNA's development of resources with remarketing funds. Balances from this account are to be paid to GNA at the end of fiscal 2006. Leasing fees for fiber optic cable are recognized over the lease terms extending as far as 2020. The current portion of deferred credits to be recorded as revenue in fiscal 2002 is included in accounts payable and other current liabilities in the Balance Sheet.

Hedging and Derivative Instrument Activities

BPA's hedging policy (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. There were no open or outstanding OTC electricity swap agreements or Exchange traded electricity futures and options at Sept. 30, 2001.

Due to changing market conditions during fiscal year 2001, previously anticipated aluminum indexed power sales transactions did not occur. As a result, BPA closed out its aluminum risk position entered into in fiscal year 2000 involving the use of both purchased and written options for aluminum. Although the exiting of these transactions effectively ended BPA's aluminum risk and cash impact, the monthly accounting and settlement will continue through 2006. As the transactions do 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, 2001, and the mark-to-market gains and losses have been recorded in the Statement of Revenues and Expenses for the year then ended.

At and for the years ended Sept. 30, 2001 and 2000, both the deferred and the realized gains and losses resulting from these transactions were not material to the consolidated FCRPS financial statements.

Written Options

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

As of Sept. 30, 2001, written call options totaling 409,600 megawatt-hours were outstanding with an average strike price of $130.25 per megawatt-hour compared to 30,000 megawatt-hours outstanding and an average strike price of $61.67 per megawatt-hour as of Sept. 30, 2000. Written put options totaling 10,112,000 megawatt-hours were outstanding as of Sept. 30, 2001, with an average strike price of $41.66 per megawatt-hour compared to 190,000 megawatt-hours outstanding and an average strike price of $64.84 per megawatt-hour as of Sept. 30, 2000. These options expire at various times through Dec. 2005. BPA records written options on a mark-to-market basis and includes gains and losses in operating revenues in the Statement of Revenues and Expenses.

Financial Instruments

All significant financial instruments of the FCRPS were recognized in the Balance Sheet as of Sept. 30, 2001 and 2000. The carrying value reflected in the Balance Sheet approximates fair value for the FCRPS's financial assets and current liabilities. The fair values of long-term liabilities are discussed in the respective footnotes.

Adoption of Statement 133

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

It is BPA's policy to document and apply as appropriate the normal purchase and normal sales exception under SFAS 133, as amended by SFAS 138 paragraph 4 (a), and Derivatives Implementation Group issue C15: "Scope Exceptions: Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." For all other non-hedging related derivative transactions BPA applies fair value accounting and records the amounts in the current period Statement of Revenues and Expenses. Bonneville may also elect to use special hedge accounting provisions allowed under SFAS 133 for transactions that meet certain documentation requirements. As of Sept. 30, 2001, BPA had no outstanding transactions accounted for under the special hedge accounting provisions.

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

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

As stated above, BPA recorded a $168 million SFAS 133 transition adjustment loss at the beginning of fiscal year 2001. Subsequently, BPA recorded $48 million of gains from SFAS 133 fair value application during the remainder of the fiscal year. This amount included quarterly fair value adjustments to bookout transactions and certain option and physical forward sales and purchase transactions. The net result for the year ended Sept. 30, 2001 for total SFAS 133 fair value accounting application is $120 million loss.

EITF 98-10 Application

In Nov. 1998, the Emerging Issues Task Force (EITF) of the 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 initially its operations do not meet the guidelines established for trading activities. For fiscal year 2001, BPA applied the parameters outlined in 98-10 and found that although trading activities may exist as defined under EITF 98-10, BPA already applies fair value accounting to these activities under FAS 133 application.

Recent Accounting Pronouncements

In June 2001, FASB issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS 141 and 142 are not relevant to BPA.

In June 2001, FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS 143 will be effective for BPA starting with the fiscal year ending Sept. 30, 2003.

In August 2001, FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS 144 address financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS 144 will be effective for BPA starting with the fiscal year ending Sept. 30, 2003.

It is too soon to determine the impacts of SFAS 143 and SFAS 144 on BPA's financial statements.

2. Long-Term Debt

To finance its capital programs, BPA is authorized by the Federal Columbia River Transmission System Act to issue to the U.S. Treasury up to $3.75 billion of interest-bearing debt with terms and conditions comparable to debt issued by U.S. government corporations. A portion ($1.25 billion) of the $3.75 billion is reserved for conservation and renewable resource loans and grants. At Sept. 30, 2001, $492.8 million of this reserved amount and $2,195.7 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, 2001, for similar maturities exceeds carrying value by approximately $389 million, or 14 percent. BPA's policy is to refinance debt that is callable when associated benefits exceed costs. The table on page 39 reflects the terms and amounts of long-term debt.

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 $68.8 million for fiscal 2001 and $67.5 million for 2000, and $64.9 million for 1999. The weighted-average interest rate was 6.9 percent in 2001, and 7.1 percent in 2000 and 1999.

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, 2001.

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)
2002	$ 23,913
2003	46,687
2004	73,484
2005	110,989
2006	68,939
2007+	4,346,918
Total	***$ 4,670,930***

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

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 1989	none	2002	8.65%		$ 66,000	$ 66,000
September 1999	none	2002	6.20%	$ 40,000		106,000
November 1999	none	2002	6.40%	40,000		146,000
January 1996	none	2003	5.90%	60,000		206,000
April 2000	none	2003	6.85%	40,000		246,000
July 2000	none	2003	6.95%		32,000	278,000
August 2000	none	2003	6.85%	15,300		293,300
September 1999	none	2003	6.30%	20,000		313,300
January 1997	none	2004	6.80%	30,000		343,300
May 1999	none	2004	5.95%	26,200		369,500
June 2001	none	2004	4.75%	50,000		419,500
July 2000	none	2004	7.00%	50,000		469,500
September 1999	none	2004	6.40%	20,000		489,500
January 2000	none	2005	7.15%	53,500		543,000
January 2001	none	2005	5.65%	20,000		563,000
January 2001	none	2005	5.65%	25,000		588,000
May 1997	none	2005	6.90%	80,000		668,000
September 2000	none	2005	6.70%	20,000		688,000
August 1996	none	2006	7.05%	70,000		758,000
September 2000	none	2006	6.75%	40,000		798,000
August 1997	none	2007	6.65%	111,300		909,300
February 1993	1998	2008	6.95%	17,612		926,912
April 1998	none	2008	6.00%	75,300		1,002,212
April 1998	none	2008	6.00%	25,000		1,027,212
August 1998	none	2008	5.75%	40,000		1,067,212
September 1998	none	2008	5.30%		104,300	1,171,512
May 1998	none	2009	6.00%	72,700		1,244,212
May 1998	none	2009	6.00%		37,700	1,281,912
July 1989	none	2009	8.55%		40,000	1,321,912
January 2001	none	2010	6.05%	30,000		1,351,912
January 2001	none	2010	6.05%	60,000		1,411,912
January 1996	2001	2011	6.70%		30,000	1,441,912
May 1998	none	2011	6.20%	40,000		1,481,912
June 2001	none	2011	5.95%	25,000		1,506,912
August 2001	none	2011	5.75%	50,000		1,556,912
November 1996	2001	2011	6.95%	40,000		1,596,912
January 1998	none	2013	6.10%	60,000		1,656,912
August 1993	1998	2013	6.75%		40,000	1,696,912
September 1998	none	2013	5.60%		52,800	1,749,712
January 1994	1999	2014	6.75%		50,000	1,799,712
February 1999	none	2014	5.90%	60,000		1,859,712
November 1996	2001	2016	7.20%		40,000	1,899,712
July 1995	2000	2025	7.70%	37,730		1,937,442
August 1995	2000	2025	7.70%	65,000		2,002,442
April 1998	2008	2028	6.65%	50,000		2,052,442
August 1998	none	2028	5.85%	106,500		2,158,942
August 1998	none	2028	5.85%	112,300		2,271,242
May 1998	2008	2032	6.70%	98,900		2,370,142
August 1993	1998	2033	6.95%	110,000		2,480,142
October 1993	1998	2033	6.85%	108,400		2,588,542
October 1993	1998	2033	6.85%	50,000		2,638,542
January 1994	1999	2034	7.05%	50,000		2,688,542
				$ 2,195,742	***$ 492,800***	***$ 2,688,542***
Less current portion						(106,000)
						$ 2,582,542

(a) The weighted average interest rate was 6.5 percent on outstanding long-term debt as of Sept. 30, 2001. All construction, conservation, fish and wildlife, and Corps/Reclamation direct funding bonds are term bonds.

(b) Corps/Reclamation direct funding.

4. Nonfederal Projects

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

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

Operating expense of $217 million in fiscal 2001, $174 million in fiscal 2000 and $200 million in fiscal 1999 for the projects is included in operations and maintenance in the accompanying Statements of Revenues and Expenses. Debt service for the projects of $477 million, $561 million and $651 million for fiscal 2001, 2000 and 1999, respectively, is reflected as nonfederal projects expense in the accompanying Statements of Revenues and Expenses.

The recorded value of all Energy Northwest debt exceeds fair value by $230 million or 4 percent based on discounting the future cash flows using interest rates for which similar debt could be issued at Sept. 30, 2001. 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, 2001.

Nonfederal Projects
Thousands of dollars

	Debt repayments
2002	$ 217,459
2003	288,646
2004	323,155
2005	278,438
2006	313,527
2007+	4,750,724
Total	***$ 6,171,949***

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 most of its electric utility customers. These contracts result in payments to the utilities, which must be passed through to its qualified residential and irrigation loads, if a utility's average system cost exceeds BPA's priority firm power rate.

Subsequently, contract termination agreements were signed by all actively exchanging Pacific Northwest utilities except The Montana Power Co. (which had been receiving no benefits), whereby payments were made by BPA to settle the utilities' and BPA's rights and obligations under the residential exchange program through June 30, 2001, and in some cases, through June 30, 2011. In Oct. 2000, BPA's investor owned utility (IOU) customers signed settlement agreements for settlement of the period running from July 1, 2001 through Sept. 30, 2011. These agreements provide for both sales of power and cash payments to the IOUs.

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. BPA paid irrigation assistance payments of $25 million and $17 million for 1997 and 2001 respectively. Future irrigation assistance payments ultimately could total $733 million and are scheduled over a maximum of 66 years. The May 2000 Interim Cost Reallocation Report prepared by Reclamation resulted in approximately $77 million of Columbia Basin Project costs being moved from irrigation to commercial power. BPA is required by Public Law 89-448 to demonstrate that reimbursable costs of the FCRPS will be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects, which are beyond the ability of the 22 irrigation water users to repay. These requirements are met by conducting power repayment studies including schedules of distributions at the proposed rates to demonstrate repayment of principal within the allowable repayment period.

The table below summarizes future irrigation assistance distributions as of Sept. 30, 2001.

Irrigation Assistance

Thousands of dollars

	Distributions	
2002	$	—
2003		—
2004		739
2005		—
2006		—
2007+		732,493
Total	***$***	***733,232***

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 $8.3 million. For the Decontamination Liability, Decommissioning Liability and Excess Property Insurance policy, the maximum assessment is $12.6 million. For the Business Interruption and/or Extra Expense Insurance policy, the maximum assessment is $4.8 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 named the Satsop Redevelopment Project. In June 1999, Energy Northwest submitted a site restoration plan to the state of Washington's Energy Facility Site Evaluation 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 up to $60 million. Management is studying options to lower the costs and 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, 2001.

Decommissioning costs for Columbia Generating Station are charged to operations over the operating life of the project. An external decommissioning sinking fund for costs is being funded monthly for Columbia Generating Station. The sinking fund is expected to provide for decommissioning at the end of the project's operating life in accordance with 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, 2001, 2000 and 1998 were approximately $4 million per year. The sinking fund balance at Sept. 30, 2001, is $71 million.

In January 1993, the Portland General Electric board of directors formally notified BPA of its intent to terminate the operation of the Trojan plant. PGE's rate filing in December 1997 with the Oregon Public Utility Commission included an estimated total decommissioning liability of $424 million (in 1997 dollars). The current remaining estimate of $299 million is based on site-specific studies less actual expenditures to date. As of Sept. 30, 2001, BPA's 30-percent share of this estimated remaining liability is $69 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 1999, 2000 and 2001. For the period 1995 through 2001, funding for the Trojan decommissioning trust fund is being applied directly to the decommissioning expenses. The decision to terminate the plant is not expected to result in the acceleration of debt-service payments. BPA will continue to recover its share of Trojan's costs through rates and decommissioning trust fund withdrawals. Decommissioning costs are included in operations and maintenance expense in the Statements of Revenues and Expenses.

Environmental Cleanup

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

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 $15 million, $17 million and $19 million for fiscal 2001, 2000 and 1999, respectively. BPA's continued cost of these commitments is expected to approximate $15 million per year over the next five years. These commitments expire at various periods over the next 19 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. Current rates recover the additional costs of the Subscription obligations through 2006. BPA's trading floor enters into sales commitments to sell expected surplus generating capabilities at future dates and purchase commitments to purchase power at future dates when BPA forecasts a shortage of generating capability and prices are favorable. Further, BPA enters into these contracts throughout the year to maximize its revenues on estimated surplus volumes. BPA records these sales and purchases in the month the underlying power is sold or purchased.

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 $383 million for fiscal 2001 ($4,279 million Operating Revenues less $48 million SFAS 133 mark-to-market, $601 million U.S. Treasury Credits for Fish, $955 million Operations and Maintenance and $2,292 million Purchased Power Expenses) as shown in the Statement of Revenues and Expenses.

Major Customers

During fiscal 2001, 2000 and 1999, 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
2001				
Unaffiliated Revenues	$ 3,824,658	$ 454,011	$ —	$ 4,278,669
Intersegment Revenues	63,394	192,662	(256,056)	—
Operating Revenues	***$ 3,888,052***	***$ 646,673***	***$ (256,056)***	***$ 4,278,669***
Net Operating Margin	***$ 180,790***	***$ 363,822***	***$ (161,587)***	***$ 383,025***
2000				
Unaffiliated Revenues	$ 2,674,556	$ 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***

SCHEDULE OF AMOUNT AND ALLOCATION OF PLANT INVESTMENT

Federal Columbia River Power System
As of Sept. 30, 2001 — 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	$ 5,209,110	$ 4,907,584	$ 301,526	$ 5,209,110	$ —	$ —	$ —
Bureau of Reclamation							
Boise	115,827	16,576	—	16,576	(475)	40,434	39,959
Columbia Basin	1,861,365	1,198,576	1,632	1,200,208	494,514	142,920	637,434
Green Springs	35,509	11,170	—	11,170	9,934	8,070	18,004
Hungry Horse	146,526	118,863	834	119,697	—	—	—
Minidoka-Palisades	380,494	108,940	—	108,940	145	55,313	55,458
Yakima	214,294	6,014	122	6,136	13,594	127,140	140,734
Total Bureau Projects	***2,754,015***	***1,460,139***	***2,588***	***1,462,727***	***517,712***	***373,877***	***891,589***
Corps of Engineers							
Albeni Falls	46,484	39,923	2,776	42,699	—	—	—
Bonneville	1,348,753	871,663	73,085	944,748	—	—	—
Chief Joseph	615,881	565,416	10,300	575,716	—	163	163
Cougar	62,506	20,311	1	20,312	—	3,288	3,288
Detroit-Big Cliff	68,337	40,794	1,438	42,232	—	5,046	5,046
Dworshak	371,783	314,687	1,215	315,902	—	—	—
Green Peter-Foster	92,508	49,551	2,838	52,389	—	6,170	6,170
Hills Creek	49,388	17,640	139	17,779	—	4,605	4,605
Ice Harbor	208,554	148,413	1,405	149,818	—	—	—
John Day	637,312	473,060	17,257	490,317	—	—	—
Libby	571,885	428,891	2,343	431,234	—	—	—
Little Goose	249,473	207,553	464	208,017	—	—	—
Lookout Point-Dexter	106,945	48,231	6,794	55,025	—	1,488	1,488
Lost Creek	149,741	26,971	10	26,981	—	2,186	2,186
Lower Granite	402,663	328,342	962	329,304	—	—	—
Lower Monumental	267,701	224,483	569	225,052	—	—	—
McNary	362,799	283,839	5,291	289,130	—	—	—
The Dalles	393,766	297,306	47,312	344,618	—	—	—
Lower Snake	258,493	255,216	739	255,955	—	—	—
Columbia River Fish Bypass	717,031	239,145	442,140	681,285	—	—	—
Total Corps Projects	***6,982,003***	***4,881,435***	***617,078***	***5,498,513***	***—***	***22,946***	***22,946***
Irrigation Assistance at 12 Projects having no power generation	201,179	—	—	—	157,144	44,035	201,179
Total Plant Investment	***15,146,307***	***11,249,158***	***921,192***	***12,170,350***	***674,856***	***440,858***	***1,115,714***
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	***$ 15,230,053***	***$ 11,251,994***	***$ 928,461***	***$ 12,180,455***	***$ 733,232***	***$ 444,539***	***$ 1,177,771***

(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	—	—	—	—	34,149	17.76%
Columbia Basin	—	16,943	6,073	154	553	91.05%
Green Springs	—	—	—	—	6,335	59.43%
Hungry Horse	—	26,829	—	—	—	81.69%
Minidoka-Palisades	—	64,298	2,554	10,475	122,209	29.97%
Yakima	—	1,984	49,629	240	15,571	9.21%
Total Bureau Projects	***—***	***110,054***	***58,256***	***10,869***	***178,817***	***73.02%***
Corps of Engineers						
Albeni Falls	176	265	—	3,344	—	91.86%
Bonneville	400,677	—	—	1,266	2,062	70.05%
Chief Joseph	—	—	4,977	6,025	29,000	93.48%
Cougar	548	38,358	—	—	—	32.50%
Detroit-Big Cliff	219	20,840	—	—	—	61.80%
Dworshak	9,618	31,467	—	14,796	—	84.97%
Green Peter-Foster	365	30,270	—	1,644	1,670	56.63%
Hills Creek	628	26,376	—	—	—	36.00%
Ice Harbor	55,406	—	—	3,330	—	71.84%
John Day	90,790	17,989	—	11,807	26,409	76.94%
Libby	—	94,973	876	14,165	30,637	75.41%
Little Goose	34,737	—	—	4,115	2,604	83.38%
Lookout Point-Dexter	744	49,097	—	591	—	51.45%
Lost Creek	—	53,020	24,506	29,418	13,630	18.02%
Lower Granite	55,571	—	—	12,946	7,842	81.78%
Lower Monumental	39,379	—	—	2,853	417	84.07%
McNary	68,818	—	—	4,851	—	79.69%
The Dalles	47,059	—	—	2,067	22	87.52%
Lower Snake	2,538	—	—	—	—	99.02%
Columbia River Fish Bypass	7,240	28,506	—	—	—	95.01%
Total Corps Projects	***811,513***	***391,161***	***30,359***	***113,218***	***114,293***	***78.75%***
Irrigation Assistance at 12 Projects having no power generation	—	—	—	—	—	78.11%
Total Plant Investment	***811,513***	***501,215***	***88,615***	***124,087***	***293,110***	***77.18%***
Repayment Obligation Retained by Columbia Basin Project	—	—	—	—	—	100.00%
Investment in Teton Project (b)	—	9,151		2,433	—	80.70%
Total	***$ 811,513***	***$ 510,366***	***$ 88,615***	***$ 126,520***	***$ 293,110***	***77.22%***

PRICEWATERHOUSECOOPERS

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

In our opinion, the accompanying balance sheets and the related statements of 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, 2001 and 2000, 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, 2001, 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.

As discussed in Note 1 to the financial statements, the FCRPS changed its method of accounting for derivative instruments as of October 1, 2000.

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, 2001 (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
January 4, 2002

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

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

Repayment Demonstration

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

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

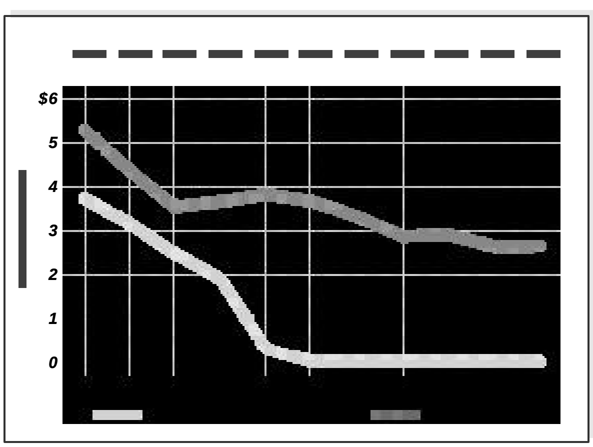
Repayment Policy

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

1. Pay the cost of obtaining power through purchase and exchange agreements (nonfederal projects).
2. Pay the cost of operating and maintaining the power system including payments related to the underfunded status of the CSRS plan.
3. Pay interest on and repay outstanding bonds issued to the Treasury to finance transmission system construction, conservation, environmental, direct-funded Corps and Reclamation improvements, and fish and wildlife projects.
4. Pay interest on the unrepaid investment in power facilities financed with appropriated funds. (Federal hydroelectric projects were all financed with appropriated funds, as were BPA transmission facilities constructed before 1978.)
5. Pay, with interest, any outstanding deferral of interest expense.
6. Repay the power investment in each federal hydroelectric project with interest within 50 years after the project is placed in service (except for the Chandler project, which has a legislated repayment period of 66 years).
7. Repay each increment of the investment in the BPA transmission system financed with appropriated funds with interest within the average service life of the associated transmission plant (40 years).

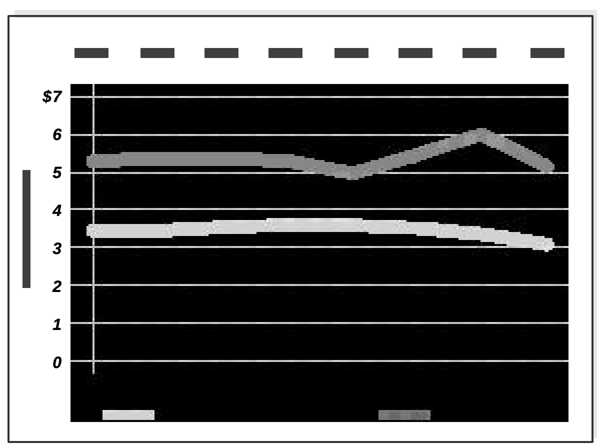
Unrepaid Federal Generation Investment

Includes future replacements



Unrepaid Federal Transmission Investment

Includes future replacements



8. Repay the appropriated investment in each replacement at a federal hydroelectric project within its service life.
9. Repay construction costs at federal reclamation projects that are beyond the ability of the irrigators to pay and are assigned for payment from commercial power net revenues within the same period available to the water users for making payments. These periods range from 40 to 66 years, with 50 years being applicable to most of the irrigation payment assistance.

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

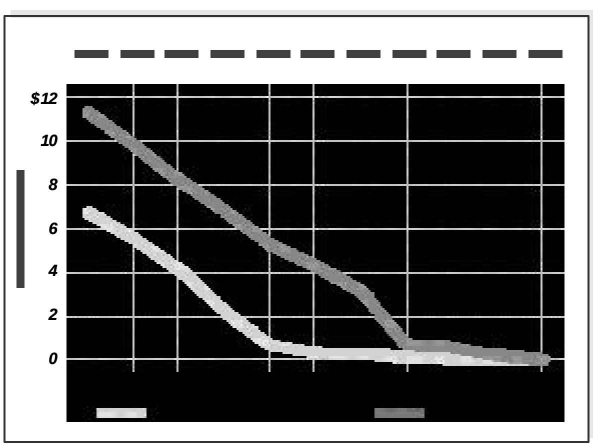
Repayment Obligation

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

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.

Unrepaid Federal Investment

Excludes future replacements



Repayment of FCRPS Investment

The graphs for Unrepaid Federal Generation and Transmission Investment on page 47 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 2001 is scheduled to be returned to the U.S. Treasury within its repayment period and ahead of due dates.

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

BPA EXECUTIVES AND OFFICES

Corporate Executives

Stephen J. Wright*
Administrator & Chief Executive Officer

Steve Hickok
Chief Operating Officer

Terry Esvelt
Senior Vice President, Employee & Business Resources

Randy Roach, acting
Senior Vice President, General Counsel

Jim Curtis
Vice President 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

Michael Weedall
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
Vice President, Business Line Management & Services

Vickie VanZandt
Vice President, Operations & Planning

* For the period of this report, Steve Wright was acting administrator. On Jan. 24, 2002, he was appointed administrator.

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

Richland CSC
Kootenai Building, Room 215
North Power Plant Loop
Richland, WA 99352
(509) 372-5751

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

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

www.bpa.gov

DOE/BP-3422 January 2002 3M