DOE/BO-604
February 1986
2.5M

Bonneville Power Administration
1985 Annual Report

Bonneville Power Administration
1985 Annual Report

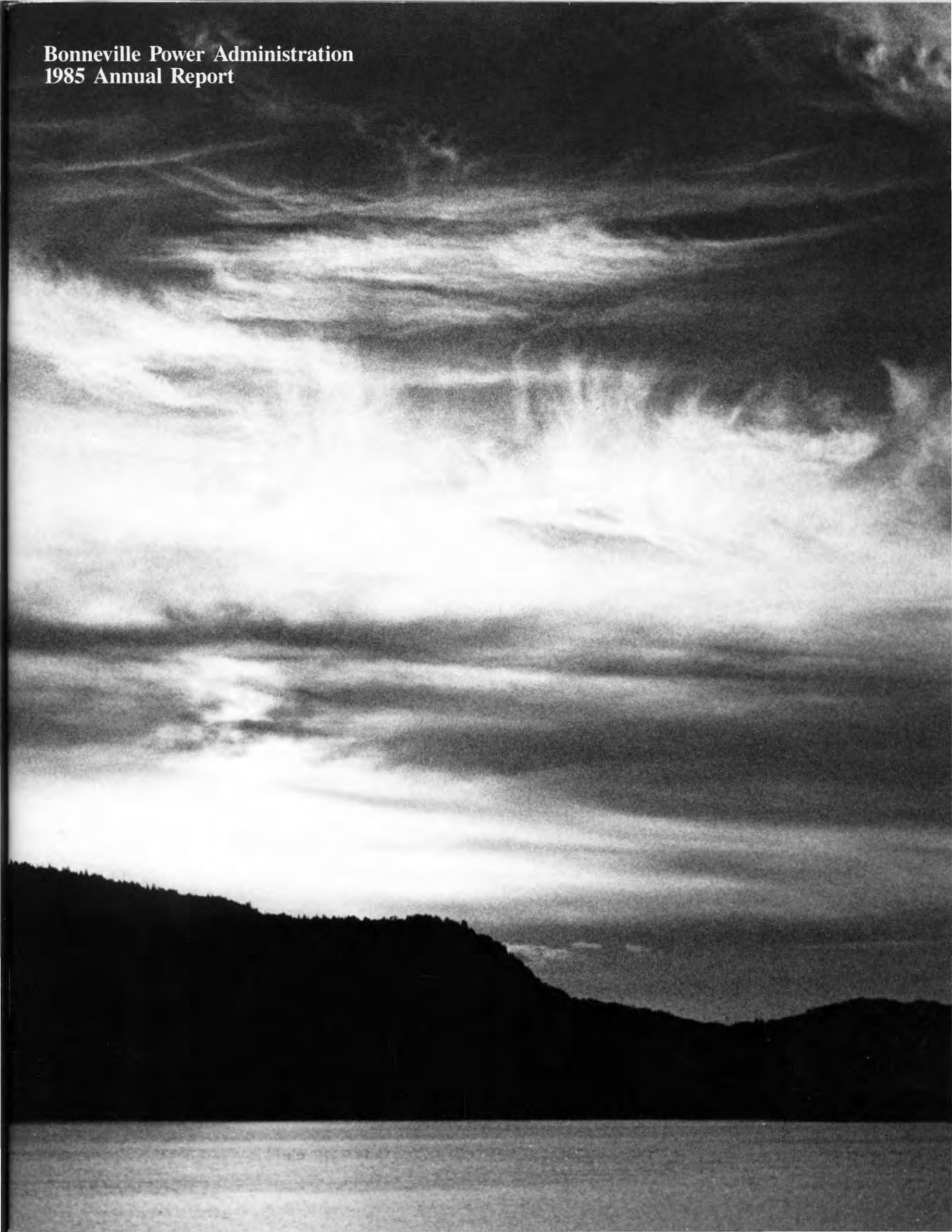


Table of Contents:

Letter to the Secretary	2
1985: A Year of Steady Progress	6
Building For The Future	10
Conserving Power And Fish	16
The WNP-3 Settlement	24
Financial Section	26
Auditor's Report	34
Official Organizational Chart	50
BPA Offices	52

Bonneville Power Administration
Sam Moment Aluminum Library
Portland, Oregon

Fiscal Highlights

(In thousands)	FY 1985	FY 1984	Percentage Increase
Sales of Electric Energy (kWh)	120,900,766	120,763,609	
Operating Revenues	$ 2,881,859	$ 2,666,475	8%
Operation and Maintenance Expense	276,390	249,347	11%
Purchase Power Expense	889,415	872,314	2%
Residential Energy Purchased	1,007,449	835,254	21%
Conservation Costs	21,934	14,118	55%
Depreciation Expense	128,999	114,390	13%
Net Interest Expense	334,224	329,725	1%
Net Revenues (Expense)	$ 223,448	$ 251,327	
Funds Returned to U.S. Treasury (includes Interest)	$ 686,391	$ 649,069	

BPA: A Profile

The Bonneville Power Administration is one of five Federal power marketing agencies. It serves the Pacific Northwest, an area of 300,000 square miles with a population of 8 million. This territory takes in Washington, Oregon, Idaho and western Montana.

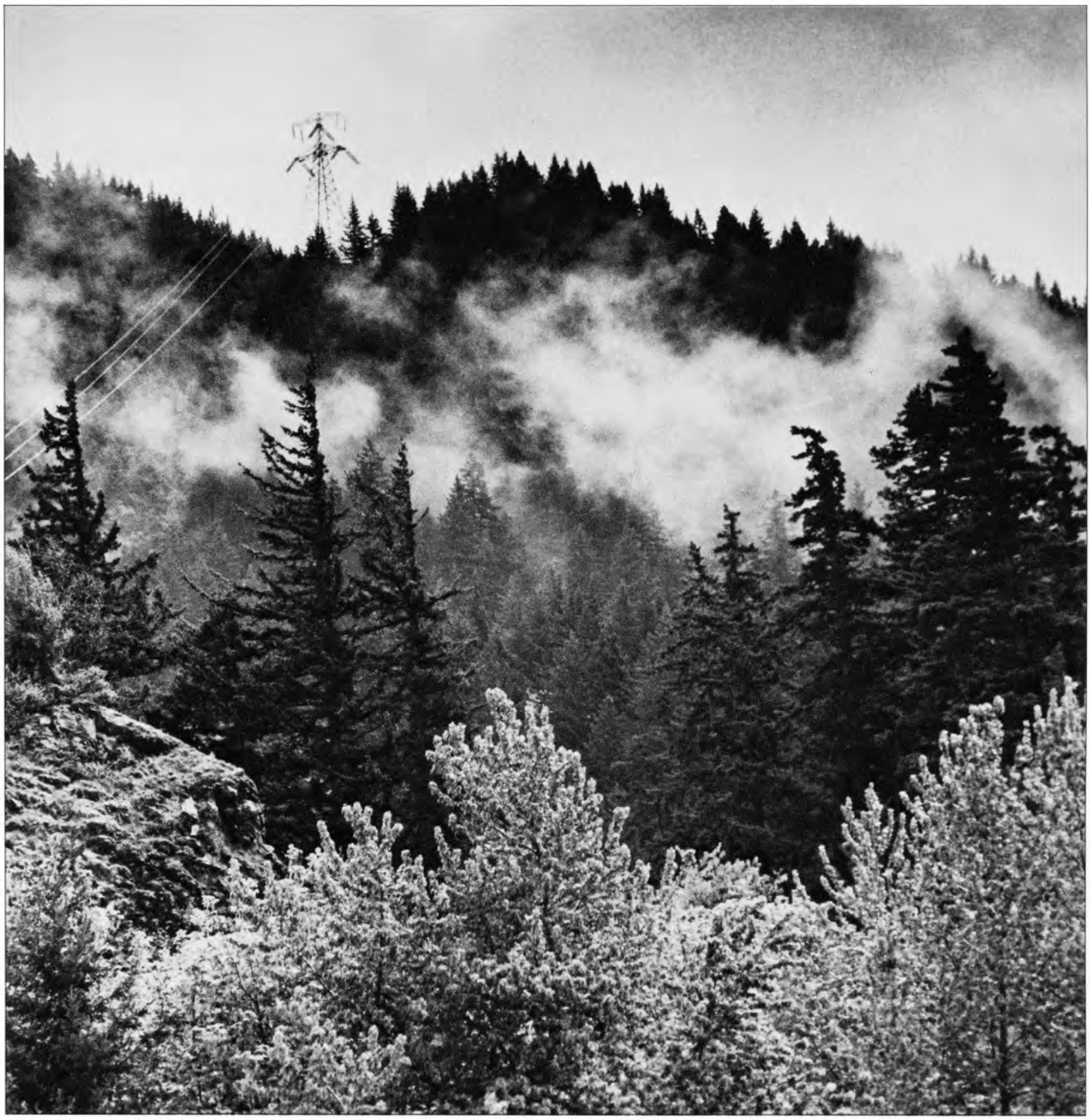
BPA markets power from 30 Federal dams built by the Corps of Engineers and the Bureau of Reclamation, as well as power from non-Federal hydro and thermal plants. BPA operates more than 14,000 circuit miles of high-voltage transmission lines. The peak capacity of this system exceeds 22 million kilowatts.

BPA has an annual budget of about $3 billion. Congress has authorized BPA to borrow from the U.S. Treasury to build new lines, carry out energy savings programs, and rebuild fish and wildlife resources reduced by power projects.

BPA uses its revenues to repay—with interest—the Federal investment in power features at the dams, plus the investment in its own transmission system. It repays a large part of the cost of irrigation and fish facilities tied in with the dams. BPA pays all its own expenses.

BPA sells power to 120 utilities owned by the public and 8 utilities owned by investors. It serves 7 Federal agencies and 14 large industries who buy power direct from BPA. Most of this industrial power goes to aluminum smelters.

BPA also markets and exchanges power with Southwest utilities over the Pacific Intertie and with utilities in British Columbia.



Honorable John S. Herrington
Secretary of Energy
Washington, D.C. 20585

Dear Mr. Secretary:

The year 1985 was one of solid performance and new possibilities for the Bonneville Power Administration.

BPA achieved its fiscal objectives, but with little help from the Pacific Northwest's economy, which remained sluggish. Unexpectedly low stream flows in the Columbia River System also reduced the amount of nonfirm power available for sale outside the region.

BPA was able to meet its financial goals by holding expenses well under projections. We paid a total of $682 million to the U.S. Treasury in fiscal 1985, with fully $226 million going to amortization. This fact demonstrates BPA's firm financial footing and determination to meet its repayment obligations, even under less than optimal operating circumstances.

Peter T. Johnson, (Administrator); Robert E. Ratcliffe, (Deputy Administrator); and James J. Jura, (Executive Assistant Administrator), left to right.

Last year, Mr. Secretary, I said that BPA had reined in the costs of its programs and would propose a priority firm power rate increase of only 3.2 percent. We did even better than that. The rate ultimately adopted for July 1985 to September 1987 represented an increase of less than 1 percent.

The Pacific Northwest has come to rely on electric energy for purposes satisfied mainly by fossil fuels elsewhere in the nation. As a result, stable electricity rates are the single most important contribution BPA can make to the recovery of the region's economy. I remain confident that we will be able to maintain this stability and predictibility in our wholesale rates for many years to come.

However, with the Northwest economy still struggling in 1985, we were concerned about potential losses of production by one of our basic industries. The region's aluminum producers, beset by low prices for ingot, were examining their options. Some companies were trimming back their domestic production and turning to foreign smelters for raw metal. Because BPA derives more than one-fourth of its revenue from Northwest smelters, we were following these events closely.

We monitored the pulse of the international aluminum market, hoping to anticipate fluctuations in price. Metals prices failed to rebound, and we determined that the threat to our revenue from falling production was real and long-term. We took steps to induce Northwest smelters to continue their Northwest operations, and even to stabilize them if possible.

BPA enacted a new 10-month incentive rate in September 1985. Meanwhile, we are continuing to look into several measures that could improve the health of the region's aluminum operations. If we determine that the measures are economically feasible, we could have them in place sometime in 1986. You will find the proposals described in this report.

Through incentive rates, BPA can help keep the region's smelters competitive. We design these special rates to maintain revenue at the highest possible level. This is good business for other consumers of electricity in the Northwest, who would pay more for their power if BPA lost the income from the smelters.

The general rates package adopted in July contained assistance for Northwest irrigators as well. Agriculture is an industry vital to our region. As in the case of the aluminum makers, farmers find themselves squeezed between rising costs of production and falling market prices. A discount on their rates for the irrigating season should help keep acreage under production here in the Northwest while maintaining BPA's revenue.

BPA's sales of surplus power outside the Northwest remained strong under the Near-term Intertie Access Policy adopted in 1984. This policy insures a fair and balanced distribution of benefits from the high-voltage Pacific Northwest - Pacific Southwest Intertie powerline.

The near-term policy gives BPA and Northwest utilities priority in use of limited intertie capacity. Nevertheless, B.C. Hydro had its best year ever on the Intertie in 1985. Low water conditions limited Northwest utilities' ability make sales in California and undoubtedly contributed to B.C. Hydro's good showing. But 1985 proved that the new policy continues to provide the Canadian supplier valuable access to California markets.

As Northwest and Canadian utilities look for markets for their surplus power, the Intertie becomes a pathway to opportunity. BPA and the City of Los Angeles have found ways to increase the capacity of the existing direct-current line by modifying the converter stations at each end. One such modification came on line in 1985 and another entered the design stage.

In the fall, promising new prospects for use of the Intertie came to light. The government of British Columbia announced that it wants to build a new dam on the Peace River, and export the power generated there. BPA invited B.C. Hydro to meet with Northwest utilities and discuss how the power could be marketed in the United States. We think a combination of export arrangements and increased coordination of our two power systems would open the door to low-cost future supplies of power for users on both sides of the border.

Closer to home, Washington Nuclear Project No. 2 at Hanford is now playing an important role in the Federal Columbia River System. In its first year of operation, the project experienced some mechanical difficulties and operated at a reduced level. Nevertheless, it provided valuable service during the Northwest's dry spell this summer. Meanwhile, Projects 1 and 3 remained under preservation.

In other Supply System business, BPA and the region's investor-owned utilities agreed to settle a major legal dispute. The suit was filed by the private utilities against BPA and the Supply System for halting construction of WNP-3 in 1983. While we strongly believe our action was correct and legally defensible, we also think the region benefits more from settlement than from long and costly litigation. If approved by the court, the settlement should close the matter at little or no cost to BPA's ratepayers.

Assistant Administrators George A. Tupper, (Operations); Edward W. Sienkiewicz, (Power); and Marvin Klinger, (Engineering), left to right.

Cost-consciousness was a prime factor in our decision to limit spending on programs to acquire kilowatts of conservation. The Northwest's surplus of electric power could last well into the 1990s, so acquiring a large amount of conservation doesn't make much economic sense. But it does make sense to develop the tools and the muscle to acquire efficiency in the future. So, we are perfecting measures and delivery systems in anticipation of future needs.

This approach is fully consonant with the plan of the Northwest Power Planning Council. Our relationship with the Council remains positive and productive. After two and one-half years of activity under the Council's 1983 Power Plan for the Northwest, BPA and the Council have demonstrated that the new system works. We have accomplished much. And while we don't walk lock-step, we have managed to march ahead in substantial agreement on most major issues.

Of all the events of 1985, one of the most gratifying was the energization of the Colstrip Transmission Project in western Montana. For more than a decade, BPA has worked with Montana Power Company and participating utilities to build a line west from the Colstrip coal-fired plants in eastern Montana. We had many environmental and technical obstacles to overcome, but we are proud of the results. The energization of the 500-kilovolt line from Garrison to Taft Substation took place this fall.

Assistant Administrators Steven G. Hickok, (Conservation); Stephen A. Ailshie, (Finance); George E. Bell, (Management Services), left to right; and Harvard P. Spigal, (General Counsel), seated.

Finally, BPA and the region passed a very important milestone in 1985. The Northwest Power Act, passed by Congress in 1980, directed the BPA to take on new responsibilities in the areas of rates, resource acquisition and conservation, among others. Congress set deadlines for certain actions to be taken over a period of five years. With fulfillment in 1985 of rate directives contained in the law, BPA met this deadline. You will find the rates discussed in some detail in this report.

It has been a long, difficult road, with some turns the authors of the Act never anticipated. But we believe the Act has proven its worth and will yield benefits to the region for many years to come. Power sales contracts are in place with public and private utilities. Proven conservation programs are either in use or ready for use as needed. a new ratemaking process is a proven success. A strong program for the improvement of fish and wildlife is in place.

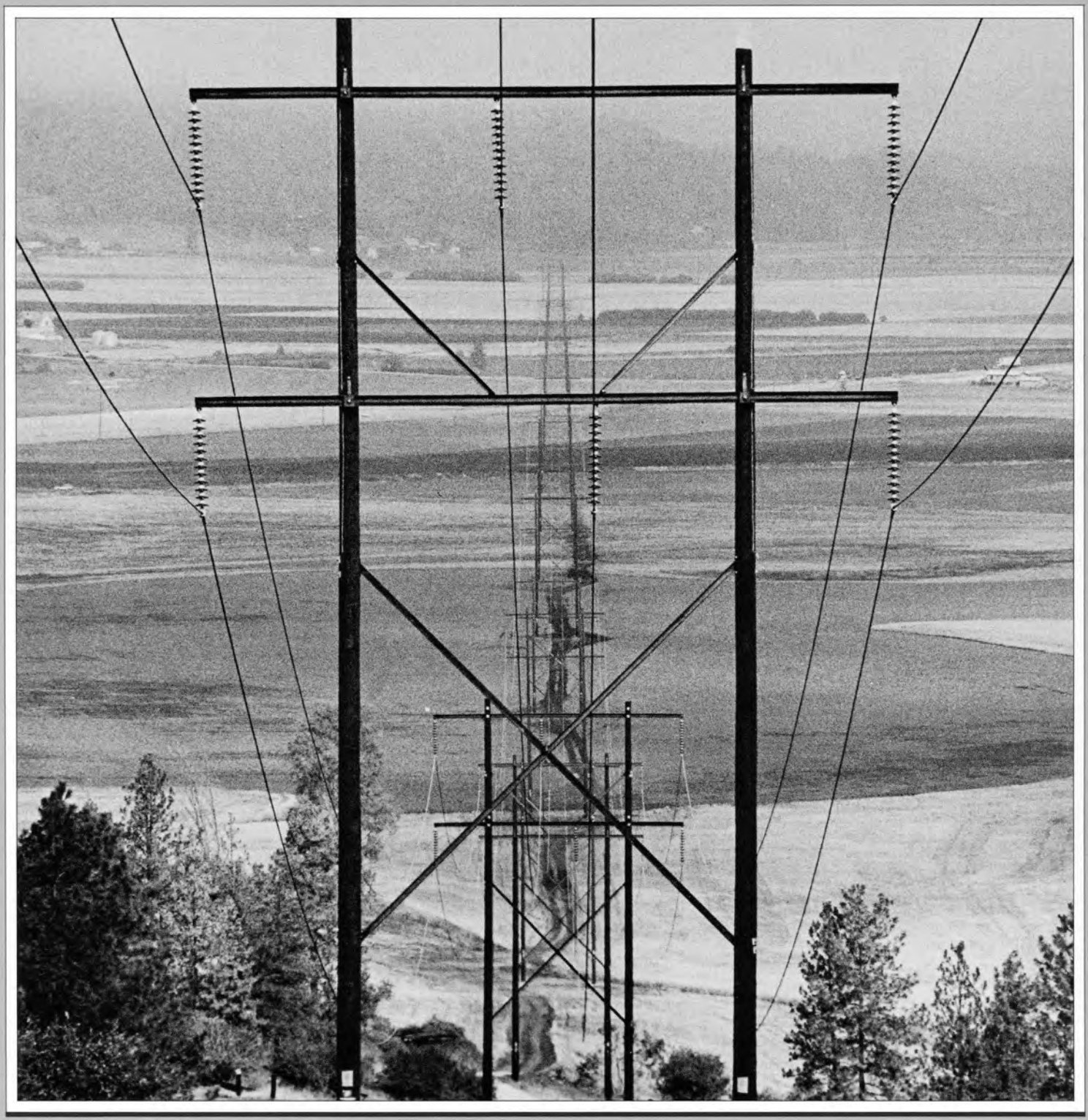
These and other accomplishments described in this report made 1985 an eventful, productive year of service for the Bonneville Power Administration. It is Bonneville's goal to deliver the best value in electricity services to its customers. I am confident that the people of BPA will continue to do this as they improve the efficiency and productivity of our Northwest utility system.

Sincerely,

Peter T. Johnson

Administrator

1985: A Year Of Steady Progress



Bonneville Power Administration's payments on the Federal investment in the Federal Columbia River Power System totaled $682 million in fiscal 1985. It was the largest yearly payment in BPA's history.

BPA paid the U.S. Treasury $374 million in interest and $226 million to amortize a portion of the principal. An additional $82 million went to cover operation and maintenance costs at the Federal dams.

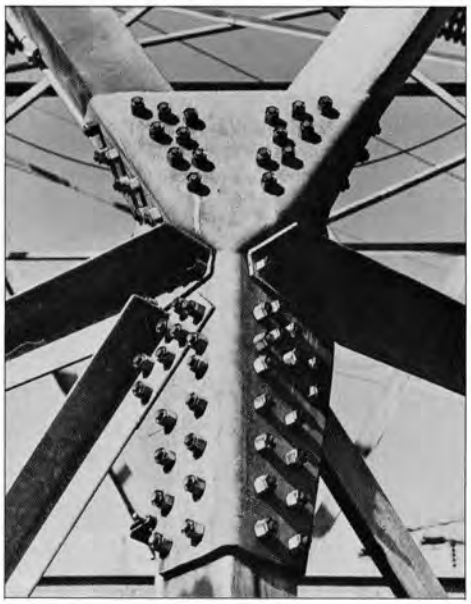
The payments were made despite low water conditions during the summer that reduced the amount of power that could be generated and sold. Although revenues for the year were higher than in fiscal 1984, they fell below expectations.

BPA was able to meet its repayment commitments because of: internal actions to control costs; incentive rates designed to preserve industrial load; and a vigorous, sustained effort—supported by BPA's new Intertie Access Policy—to market surplus power. The agency held down its operation and maintenance expenses and reduced its borrowing costs.

Since 1938 when BPA first began marketing power, it has returned $5.5 billion to the Treasury. It has paid a total of $3.4 billion in interest and repaid $866 million of the Government's investment in the power system.

BPA Adjusts Its Rates

BPA is required by law to recover the U.S. Treasury investment in the Federal Columbia River Power System—with interest. The Congress has also directed the agency to operate on a balanced budget.



Stability and predictability in its fiscal affairs are assets as valuable as tower steel to BPA.

BPA also pays a portion of the cost of Northwest irrigation projects and fish facilities. Its income comes from the sale of electric power and transmission services at the wholesale level.

BPA has raised its electric rates seven times since these rates were first established in 1938. Five of these increases have taken place since 1979 when the construction of three nuclear generating plants began to drive up BPA's costs.

About 40 percent of the increases that occurred in this period were due to construction costs of the Washington Public Power Supply System nuclear generating plants WNP-1, 2 and 3. These costs now appear to be under control. WNP-2 has been completed, and the construction of WNP-1 and 3 has been suspended. WNP-1 and 3 are being preserved so construction can be restarted when the plants are needed.

The most recent rate increase became effective on July 1, 1985. Although all of BPA's rates were changed, its priority firm rate barely budged. It rose less than 1 percent. This rate governs the class of power sold to utilities for resale to homes and small farms.

Ten months of analysis and formal rate hearings preceded the adjustment in July 1985. The new rates are based on detailed studies of loads, revenue requirements and costs, as well as public testimony. The official records of the hearings, which were conducted over a period of 8 months, cover 40,000 pages of testimony, exhibits, hearing transcripts, public comments, and briefs.

At the conclusion of this process, BPA raised the priority firm rate from 2.2 cents per kWh to 2.22 cents.

The priority firm rate includes a 3.7 mills per kilowatt-hour energy discount for irrigation sales. The discount is being offered from April through August to utilities with irrigation load.

The industrial firm power rate dropped from 2.5 cents per kWh to 2.3 cents. This brought the standard industrial rate for 14 firms who buy power direct from BPA closer to the level of the priority firm rate. These direct-service industries (DSIs) actually paid less than the standard industrial rate during most of fiscal 1985 because of incentive rates offered by BPA. The special low 7-mill per kWh off-peak rate for Hanna Nickel Smelting in southern Oregon was extended 5 years.

The standard rate for nonfirm energy sales increased from 1.9 cents per kWh to 2.2 cents (plus 0.12 cents per kWh for sales over the Pacific Intertie). The increase reflects an initial decision by a Federal Energy Regulatory Commission administrative law judge on BPA's 1981 and 1982 nonfirm energy rates. He stated that BPA erred by not including sufficient costs in its nonfirm energy rates. Most nonfirm energy sales go to California utilities.

The new rates will be in effect from July 1, 1985 to Oct. 1, 1987, a period of 27 months. The general impact of increases in BPA rates on Northwest ratepayers is now less than the current growth rate for inflation. Inflation has been moving up at the moderate clip of about 4 percent a year.

BPA will require a total of $2.9 billion a year to cover its costs during the new rate period.

BPA is in the process of developing a new rate for surplus firm power. The proposed rate will govern BPA sales of firm power to Northwest utilities as part of its long-range marketing effort. The utilities who purchase this power would sell their own displaced thermal power to Southwest utilities. In effect, they would use BPA's surplus firm power to free up power from their own thermal generating plants for sale to utilities in the Southwest.

Formal rate hearings on the proposal for a firm displacement rate were under way as the financial year came to a close.

Incentives Boost Revenues

In August, BPA offered an incentive rate to its industrial customers for a 10-month period from Sept. 1, 1985 through June 30, 1986.

BPA has the authority to offer an incentive rate to its industrial customers during adverse economic periods. But first it must show that it can expect to earn more revenue with an incentive rate than it would receive under its standard rate. The incentive rate is intended to protect BPA's revenues and to sustain industrial production in the Northwest.

Public meetings are helping BPA forge new rate policies for the Northwest aluminum industry.

The incentive rate was offered because the region's aluminum companies have been hit hard by foreign competition and low aluminum prices in the world market. The region's aluminum plants buy most of the industrial power sold by BPA.

As a result of the offer in August, the companies agreed to buy a total of 2,240 average megawatts for the 10 months. BPA's feasibility study showed that this was 190 megawatts more than BPA needed to meet its revenue test with monthly discounts ranging from .1 to .9 cents per kWh. BPA estimated that it could expect to make $12.8 million more than it would under its average standard rate of 2.35 cents per kWh. The incentive rate will average 1.9 cents per kWh.

Without an incentive rate, BPA could expect to see its industrial load drop from the August 1985 level of about 2,380 megawatts to as low as 950 megawatts by March 1986.

This is the third time BPA has initiated an incentive rate. An average rate of 2.3 cents per kWh was placed in effect for a period from Sept. 1, 1984 to Feb. 28, 1985. A second such rate, which averaged 2.2 cents per kWh, lasted from March 1, 1985 to July 1, 1985.

DSI Options Study Concluded

The 10 smelters that buy power direct from BPA have historically provided one-fourth to one-third of BPA's total revenue. In the past 2 years BPA has been partially successful in protecting this revenue stream by offering the firms special incentive rates to maintain their operations. But a broader, longer range program is needed. Otherwise, part of the burden of meeting the Federal Columbia River Power System's obligations may shift to other ratepayers.

BPA completed a study of possible options in June. The study concluded that BPA should move forward with a package of three actions designed to improve the competitive position of Northwest aluminum smelters in the world market over the long term.

The first action would tie the power rate for the aluminum industry to the world market price of aluminum ingot. The second action would increase the efficiency of the plants by modernizing their equipment through a partnership program among BPA, the aluminum companies, and State and local governments. And third, BPA would establish a long-term link between the rate charged the industries and the traditionally stable priority firm rate for utilities.

Formal rate hearings have been started and other steps taken to put these ideas into action. All three actions may be in place by mid-to-late 1986.

The options study has attracted more public interest that any other BPA program in the past 5 years. About 5,000 persons attended 13 public meetings held by BPA as part of an extensive program to involve the public in the decisions. As a result, 1,150 written comments were submitted.

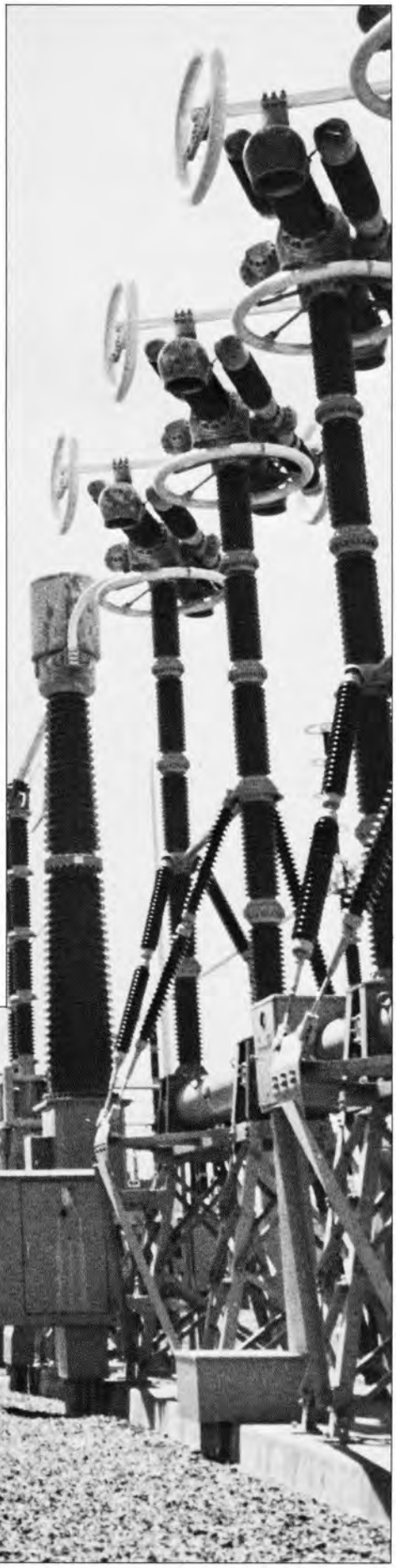
Such substations (at right) on the Pacific intertie help make electricity a major Northwest export.

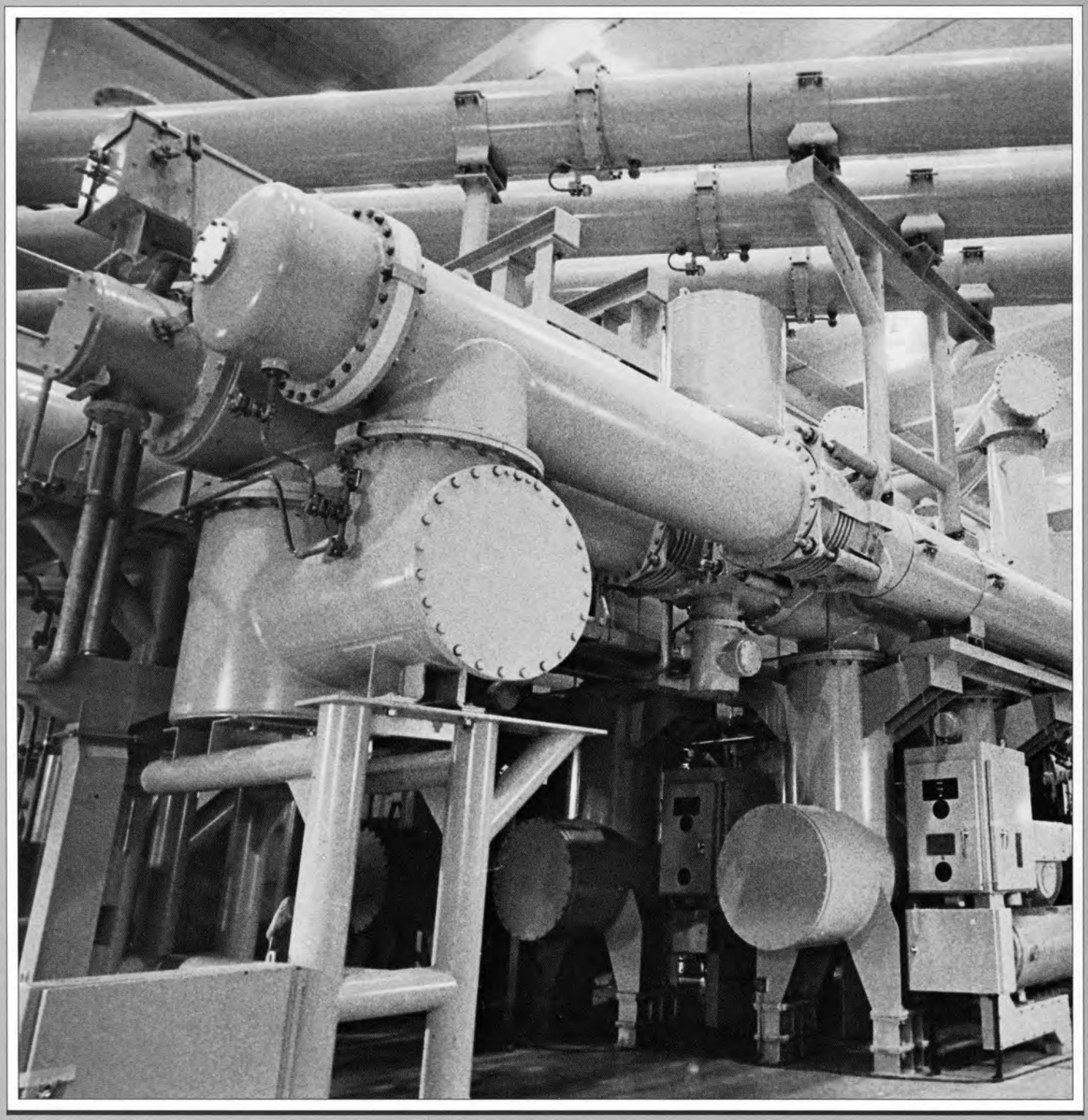
Intertie Access Policy

BPA adopted a Near Term Intertie Access Policy on June 1, 1985. The policy grew out of BPA's experience with an initial, interim policy that took effect in September 1984.

The intent of the near-term policy is: (1) to protect the financial integrity of the Federal Columbia River Power System; (2) to assure that BPA will be able to use its own intertie capacity to sell its surplus power to Southwest utilities, and (3) to equitably allocate intertie capacity to Northwest utilities according to the amount of surplus and nonfirm power each utility has.

The near-term policy is to remain in effect until it is superseded by a long-term version of the policy, which is expected to be in place in September 1986. This new policy will address such issues as long-term contracts and intertie access for new resources. As in the past, the development of this policy will involve extensive public review. The near-term policy this year withstood a major legal challenge. The U.S. Ninth Circuit Court of Appeals held that BPA's access policy is consistent with BPA's authority and obligations. The court affirmed that BPA is required to market Federal power in ways that will help make BPA self supporting and meet BPA's financial obligations.





The Office of Engineering and Construction continued to carry a heavy workload of design and construction in 1985. It is accomplishing more work with 300 fewer employees. Several important projects were started during the year; others entered their final phase.

The Colstrip transmission project will integrate the output of Colstrip generating units 3 and 4 into the BPA grid. BPA's portion of the project consists of two large substations and a double-circuit 500-kV transmission path that will extend from Townsend on the headwaters of the Missouri River across Montana to northern Idaho. A single-circuit 500-kV line will run from the Montana-Idaho border to Spokane, Wash.

BPA finished most of the construction work for a 157-mile section of the Colstrip project in western Montana in 1985. It completed that part of the project that runs from Garrison Substation near Deer Lodge to Taft Substation near the Montana-Idaho border. BPA completed the 97-mile section from Townsend to Garrison Substation in 1983.

Design work for the final 99-mile section from Taft Substation across northern Idaho to Bell Substation near Spokane, Wash. is nearly finished. Rights-of-way are being acquired and materials delivered. This section is to be energized in the fall of 1987.

All sections of the line are equipped with the world's first application of high-speed single-pole relaying and grounding equipment. This equipment makes it possible to transfer higher levels of power and maintain stable system operations.

Advances in technology have permitted the installation of new gas-insulated extra-high voltage equipment at Taft Substation. Taft's seven 500-kV gas-insulated circuit breakers require much less space than conventional equipment. The entire substation is housed within a large concrete building because of the severe winter climate at the site 4,267 feet above sea level.

During 1985, BPA erected a number of tall tubular steel poles near Missoula for esthetic reasons. The poles are believed to be the only double-circuit 500-kV tubular single poles in the United States.

Upgrading the Pacific Intertie

BPA and the Los Angeles Department of Water and Power have completed additions to their respective terminals at either end of the Pacific Intertie's 846-mile direct-current line. The terminals work in tandem. When one is converting alternating current to direct current and sending it out over the transmission line, the other is receiving the d.c. power and converting it back to a.c.

Two valve groups were added to each terminal. The voltage of the line was raised from 800 kV to 1,000 kV. This boosted the capacity of the line from 1,600 megawatts to 2,000 megawatts in February 1985.

Each party has since initiated a further expansion of its terminal to give the d.c. line an additional 1,100 megawatts of capacity. The amount of power the line can carry will increase to 3,100 megawatts, or enough power to supply three cities the size of Seattle.

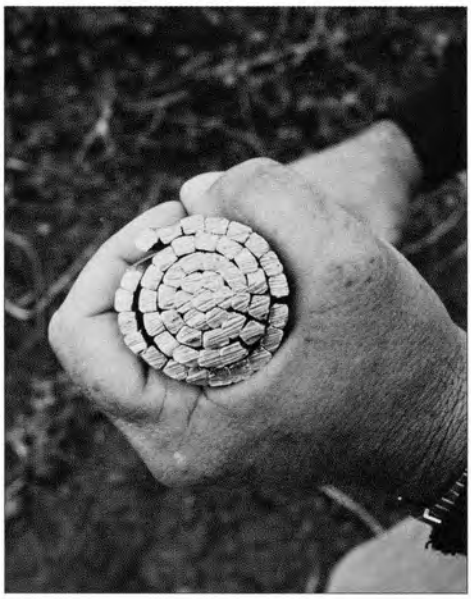
In October 1985, BPA awarded a $53 million turnkey contract to expand at the northern terminal at The Dalles, Ore. Los Angeles and its southern partners will award a similar contract for the southern terminal. A decision to proceed with construction has been delayed until 1986; the decision will depend on the results of further environmental analysis. No new transmission lines will be needed to expand the capacity.

In the meantime, planning also is moving ahead for a third 500-kV alternating-current line from southern Oregon to California. This project would add 1,600 megawatts of capacity to the Pacific Intertie by mid-1990. BPA and its northern partners plan to build the transmission facilities that will be needed in Oregon. Utilities in California will construct the facilities needed in that state.

Taft Substation is housed in a single building to protect its equipment from severe winter weather.

The Pacific Intertie has brought tremendous economic benefits to the western United States since the first line was energized in 1967. Its two 500-kV a.c. lines and its long 1,000-volt d.c. line transmit huge blocks of power.

The unscheduled interruption of these power flows has triggered blackouts in several states in the past. In 1985, BPA and Pacific Gas and Electric Co., California's largest utility, working jointly, set out to decrease the extent of future interruptions. BPA and PG&E began to replace obsolete control equipment with advanced equipment. They also began to improve the automatic corrective steps taken to minimize the impact of outages when they do occur. This work will continue in 1986.



This conductor with trapezoidal strands is a first — a breakthrough that will save millions.

New Conductor Developed

Conventional conductors for transmission lines consist of a number of round wire strands twisted rope-like into a cable. Although they resemble steel cables, the conductors are made mostly of aluminum. This year BPA began using a new type of conductor developed by its engineers. Each strand in the conductor is trapezoidal. The cross section of a single strand looks like a pyramid with its top cut off parallel to its base.

When trapezoidal strands are spun into cable, they fit closer together than circular strands. The close fit improves electrical performance. A trapezoidal conductor can carry about 20 percent more power than a conventional conductor of the same diameter.

This means that BPA can increase the capacity of a line by replacing conventional conductor with trapezoidal. Or it can move the same amount of power over a given distance using a smaller trapezoidal conductor and lighter towers. Either way, the overall saving in material is substantial.

The new design, which is regarded as a major technological advance, promises to save utilities and ratepayers millions of dollars. The design grew out of discussions with Ontario Hydro engineers.

The first application of the new design took place this year when BPA used a new trapezoidal conductor on a 91-mile section of the Bell-Boundary line. The line is being rebuilt to raise the voltage from 115 kV to 230 kV. BPA estimates the new design will save $3 million over the service life of the line.

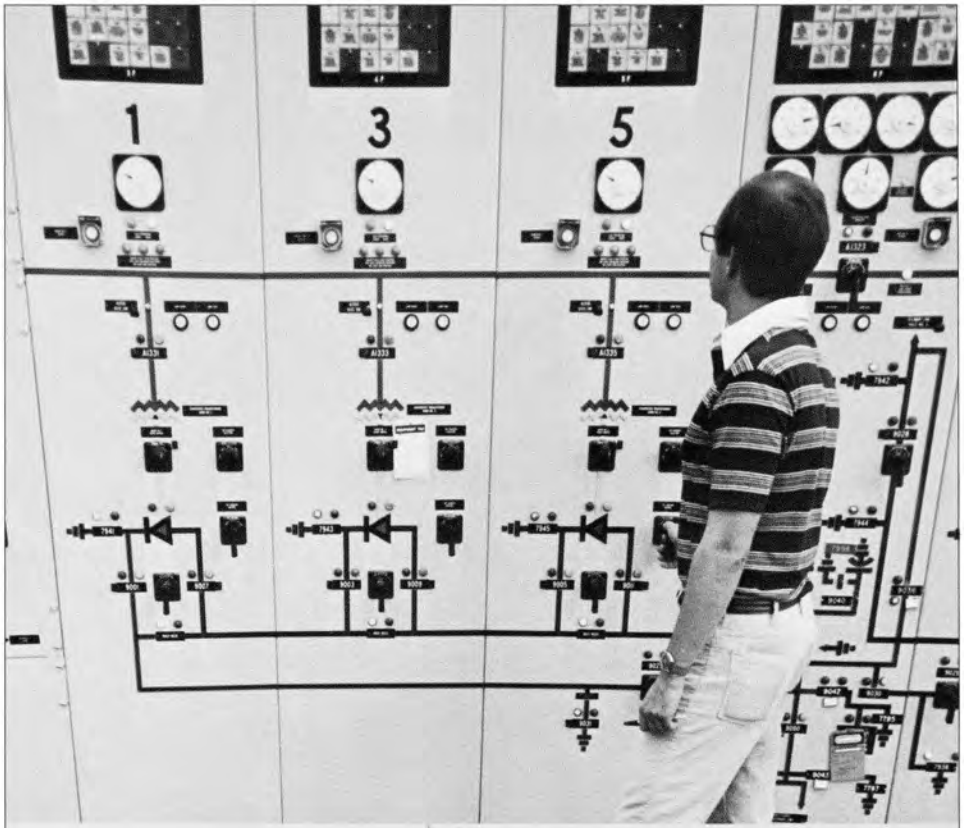
BPA currently uses 50 or 60 different types of conductor with circular strands. The new trapezoidal design is expected to reduce this assortment to nine standard conductors that can be strung using existing tower designs and line hardware.

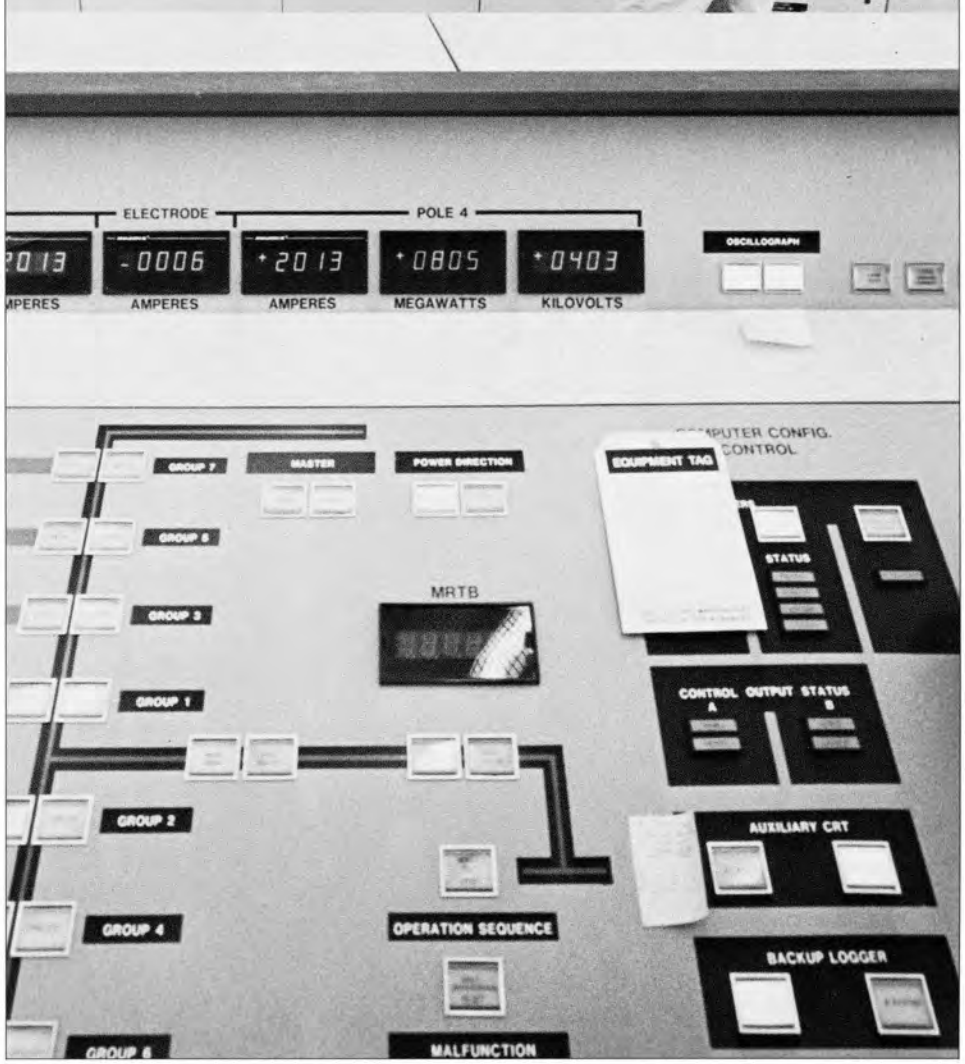
Control Centers Advance

It has been a common practice in the utility industry for nearly 20 years to operate substations by remote control. Operators monitored and controlled substation components through the power system's communications system. An operator could switch equipment on and off at substations that were often several hundred miles away. The practice has been known in the industry as supervisory control and data acquisition, or SCADA.

BPA has employed three SCADA systems, two of which have been controlled from its Dittmer Control Center at Vancouver, Wash., and one from its Eastern Control Center at Moses Lake. The oldest of these systems dates back to 1970.

In 1985, BPA signed a contract to begin replacing its SCADA systems with two up-to-date transmission control and dispatch systems. One will be furnished and installed at Vancouver to replace BPA's SCADA I and III. The second will replace SCADA II at Moses Lake, Washington.





The equipment used to monitor power flows on BPA's system gets more sophisticated with each passing year.

The two new systems are to be fully operational by 1988. They will allow dispatchers to do much more than remotely control breakers, transformers, and switches, as is done with the SCADA systems. Dispatchers will also be able to analyze power flows, identify potential problems, determine the possible effect of impending outages, and take steps to avoid or lessen the disturbances.

High-voltage D.C. Research

BPA and a group of utilities are co-sponsoring an agricultural study near the Intertie's d.c. line in central Oregon. The purpose is to learn more about possible environmental effects from electrical fields and lines associated with high voltage d.c. lines.

The study will determine whether operating the line at 1,000 kV results in any significant effects on cattle or crops. It is being conducted by Oregon State University at an installation known as the Grizzly HVDC Research Facility. The studies will continue through the fall of 1987.

System Expands

BPA placed four new substations and 426 circuit miles of new transmission line in service in 1985. At the end of the fiscal year, BPA had 383 substations and a total of 14,203 circuit miles of line.

It was operating 3,992 circuit miles at 500 kV, 709 miles at 345 kV, 1,450 miles at 287 kV, 3,974 miles at 230 kV, and 94 miles at 138 kV. Some 264 miles of d.c. line operated at 1,000 kV. The balance of the system operated at 115 kV or lower voltages. The system has 63,566,105 kVA of transformer capacity.

Operations and Maintenance

BPA is reducing the time and money required—per mile of line—to operate and maintain its transmission system.

Back in 1975, it took 120 hours of work and $4,300 to operate and maintain a mile of line. By 1985, that figure had dropped to 101 hours and $3,000 in 1984 dollars.

The workload has risen 14 percent since 1975. But the work is being accomplished with an equivalent of 109 fewer full-time employees. In view of the increased workload, BPA has realized an increased staff efficiency equivalent to 202 full-time employees and a savings of $18.3 million a year.

BPA's O&M people have accomplished these gains by boosting productivity. Management has met the increase in workload by applying technical advances, automating substation control, reducing the frequency of maintenance on certain equipment, making greater use of contractors, and improving organization and staffing.

For example, BPA is contracting nearly 80 percent of its vegetation control activities. High-pressure washing is used to clean contaminants off equipment in industrial areas. Motion analyzers watch the way circuit breakers open and close and diagnose their operating condition. And relays are being maintained with computer-driven test sets.

During 1985, BPA again sought to complete its O&M tasks with a minimum of adverse impacts on the environment. It intensified field appraisals of potential environmental problems and set up detailed plans to preserve and protect environmental quality.

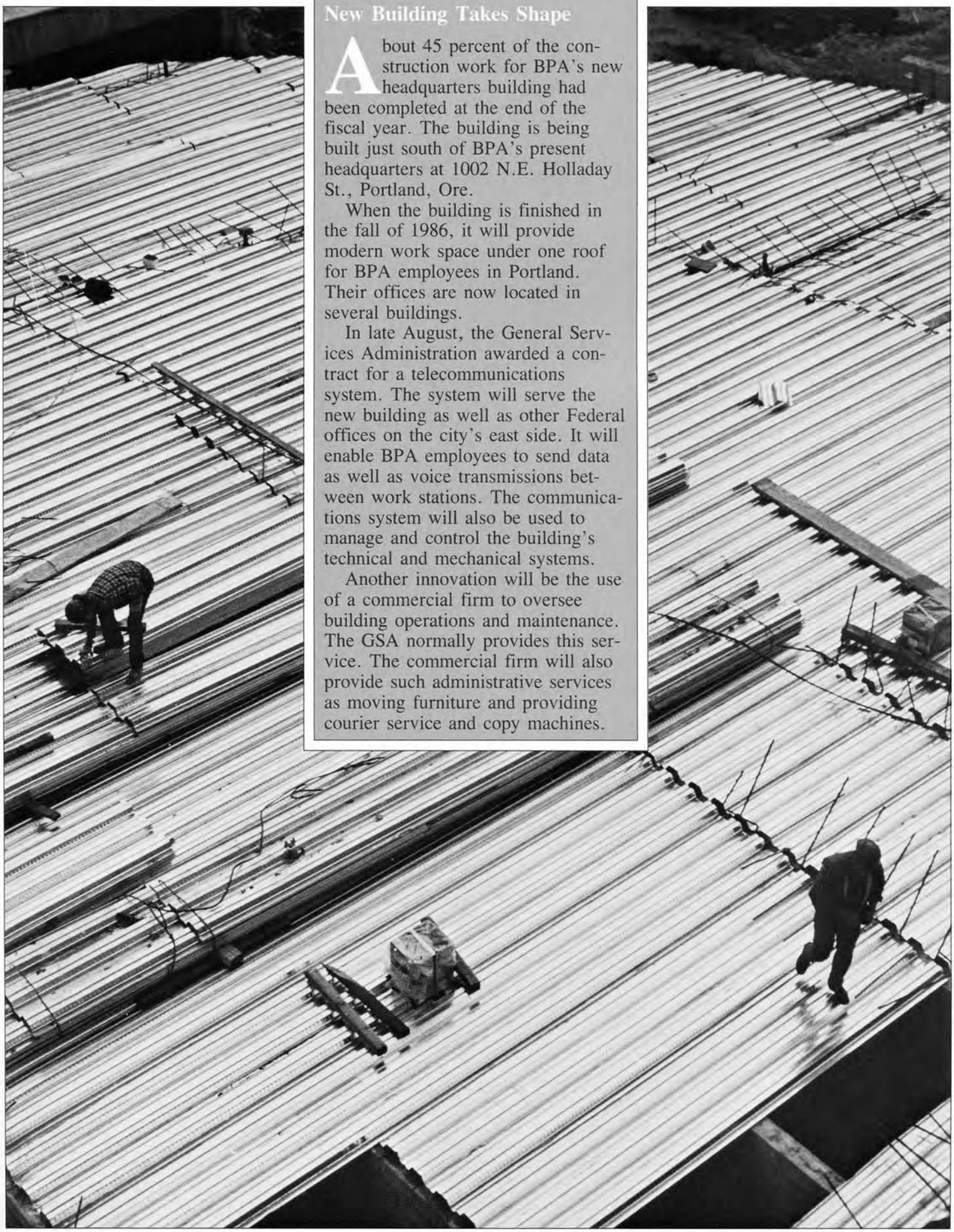
BPA, for example, has systematically inventoried all stations with capacitors containing polychlorinated biphenyls (PCBs). BPA has more than 130,000 capacitor cells containing PCBs, and it found 7,000 to be defective. The defective cells are being replaced.

Its program to manage toxic substances and hazardous waste was improved, partly as a result of a memorandum of agreement signed by BPA and the Environmental Protection Agency. BPA agreed voluntarily to conduct inspections of its facilities, test for contamination, and look for old burial sites of hazardous materials. The EPA is assisting BPA in technical matters and in training BPA personnel, especially in the area of remedial action.

BPA has also inventoried all other substations, maintenance complexes, and microwave sites in an effort to identify conditions that might harm the environment. This information data base on environmental problems is constantly being expanded and is valuable in initiating remedial and preventive actions and in revising and developing new standards.

BPA's O&M people were faced with several unusual problems in 1985. For example, BPA and the Harney County Electric Cooperative relocated and rebuilt 3 miles of line in southeast Oregon. The line was being destroyed by the rising waters of Malheur Lake, which is slowly getting larger. This project cost BPA $250,000 out-of-pocket, but it will save ratepayers $600,000 a year because the power won't have to be rerouted over another utility's system.

A great deal of emphasis is placed on safety. BPA's safety record is as good as that of any other utility, but BPA is working to improve it. A new safety awards program recognized the performance of more than 1,000 O&M workers in 1985. The awards recognize the achievement of people in the past and serve as an inducement for them to continue safe practices in the future. The program has raised employee awareness of the importance of working safely.



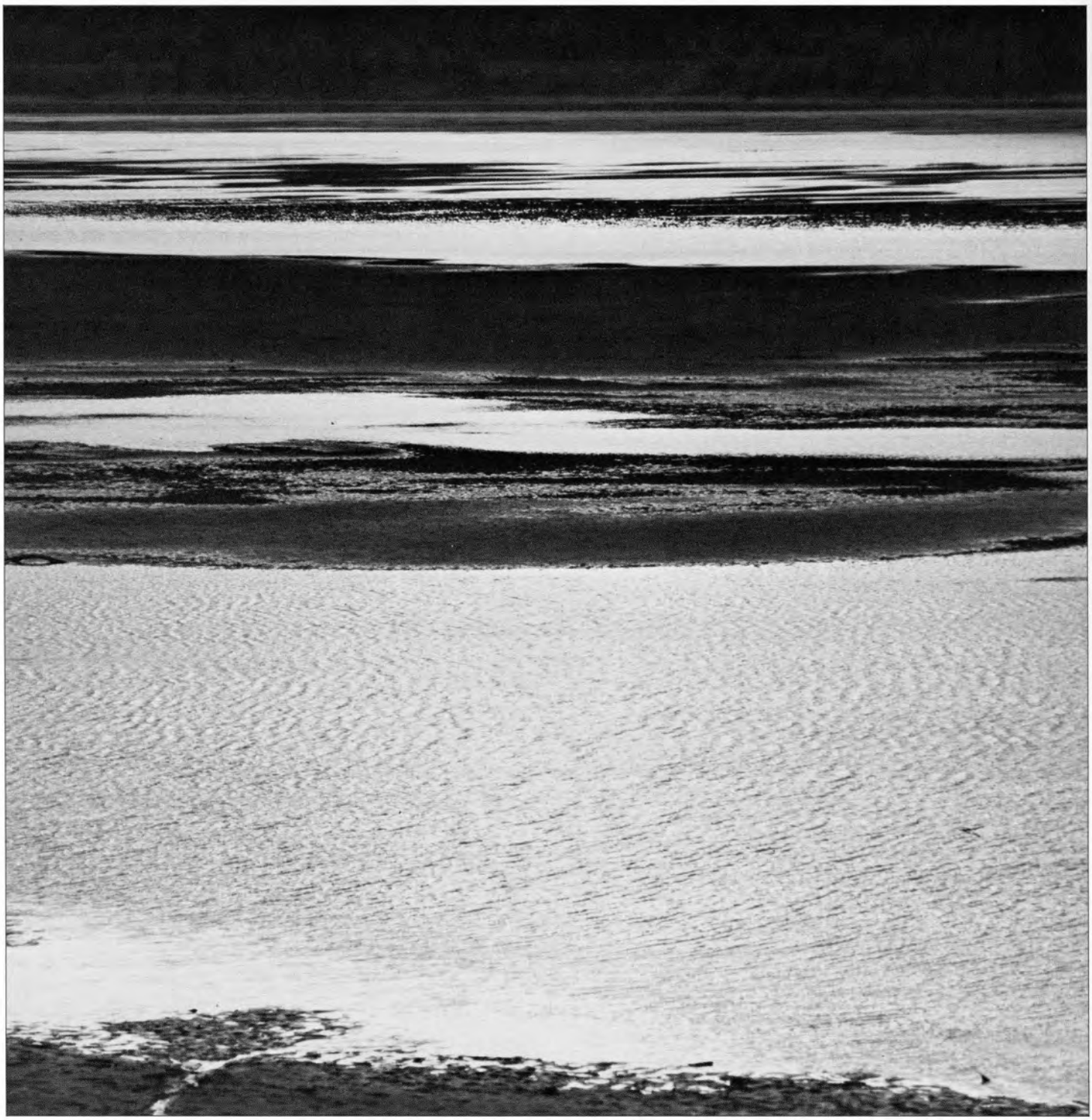
New Building Takes Shape

About 45 percent of the construction work for BPA's new headquarters building had been completed at the end of the fiscal year. The building is being built just south of BPA's present headquarters at 1002 N.E. Holladay St., Portland, Ore.

When the building is finished in the fall of 1986, it will provide modern work space under one roof for BPA employees in Portland. Their offices are now located in several buildings.

In late August, the General Services Administration awarded a contract for a telecommunications system. The system will serve the new building as well as other Federal offices on the city's east side. It will enable BPA employees to send data as well as voice transmissions between work stations. The communications system will also be used to manage and control the building's technical and mechanical systems.

Another innovation will be the use of a commercial firm to oversee building operations and maintenance. The GSA normally provides this service. The commercial firm will also provide such administrative services as moving furniture and providing courier service and copy machines.



Bonneville continues to pursue an aggressive and sophisticated program to increase the efficiency with which electric power is used. During the year, the program focused on two main goals: (1) to develop the region's capability to conserve electricity; and (2) to support and encourage acceptance of the Model Conservation Standards formulated by the Northwest Power Planning Council for new residential and commercial buildings.

BPA launched the region-wide promotion of energy-efficient new housing with its Super Good Cents Program.

BPA sponsored more than 30 pilot programs and demonstration projects in cooperation with utilities, State and local agencies, and private businesses. It tested actual energy savings and costs involved in these programs.

On The Home Front

During the year, BPA, working through utilities and public agencies, spent $48 million to weatherize 31,000 electrically heated homes. The total includes 4,100 low-income homes, 1,400 more than were weatherized in 1984. The annual power consumption of the 31,000 homes was reduced by about 12 megawatts.

House tightening measures, such as blown-in wall insulation and storm windows, were made available to all program participants for the first time in 1985. These measures were not covered by the program in previous years because it was thought they might lower indoor air quality below acceptable levels. BPA now provides information and air quality monitoring services to homeowners who decide to install these measures in their homes. BPA also participates in the mitigation of high pollutant concentrations that may be aggravated by house tightening.

New energy-tight Super Good Cents homes conserve electricity and save homeowners money.

BPA is providing technical and financial assistance to local and State governments to (1) develop building codes that will conserve electricity and (2) train building inspectors and home builders. Under the Residential Standards Demonstration Program, BPA paid the added cost of building 423 homes to the Model Conservation Standards in 1985. It is monitoring these homes and comparing them to conventionally built homes in order to learn more about the cost-effectiveness of measures required to achieve these standards.

Sixty-one of the region's utilities enrolled in BPA's Super Good Cents Program which provides marketing and technical support for new, highly energy-efficient homes.

Hood River Saves Energy

The $20 million conservation program in Oregon's Hood River County is nearing completion. BPA is paying the full cost of insulating and tightening electrically heated homes in rural areas of the county and in the City of Hood River. About 90 percent of all modifications recommended for the homes and requested by the owners have been installed.

The program is a cooperative effort on the part of BPA, Pacific Power & Light Co., and the Hood River Electric Cooperative. It is designed to determine how much energy can be saved in an intensive, short-term effort in a typical Northwest setting.

New Method Finances Conservation

The Eugene Water and Electric Board and BPA successfully attempted a new method of financing conservation this past year. They cooperated in the sale of $17 million worth of municipal revenue bonds to fund the weatherization of homes in and around Eugene, Ore., over the next 3 years. Eugene issued the bonds. BPA will pay Eugene an amount equal to the debt service. This is the first time this type of financing has been used in the Northwest. In the past, BPA has relied exclusively on borrowings from the U.S. Treasury to fund residential conservation.

The interest on the bonds came in two percentage points below the rate at which BPA could have borrowed from the U.S. Treasury, saving some $1.8 million in overall costs for the conservation work at Eugene.

Other Projects Move Ahead

BPA in 1985 committed $10 million to install conservation measures in 177 institutional buildings throughout the region. This work is expected to reduce the demand for electricity by 5 megawatts. Funds spent in this area also bought training for energy auditors, as well as technical studies and on-site analyses. BPA paid for 256 detailed energy use analyses of buildings.

An additional $1.7 million was spent on five contracts to test how best to conserve electricity in commercial buildings. BPA is buying the actual energy that is saved over the period of each contract. This arrangement draws a third party into the financing of conservation measures.

BPA installed more energy-efficient street lights in 1985. It paid $1.6 million for 10,000 new fixtures, replacing less-efficient mercury arc lamps with sodium and metal halide lamps.

BPA's program to improve the energy efficiency of irrigated agriculture is now 4 years old. The number of utilities taking part has risen to 27. The program is identifying inefficiencies in irrigation systems and practices. It encourages the use of more efficient management practices and irrigation equipment.

A new facet of this program has led to the setting up of nine weather stations that collect and relay data to individual farms. This information makes it possible for the farm operators to apply water to crops only when needed to maintain adequate moisture levels in the soil and thus reduce both water and power consumption.

BPA hired engineering firms to conduct energy audits of 25 industrial plants that process foods or produce pulp, paper, or lumber. The purpose of this program is to determine if there is a systematic way to estimate cost-effective energy savings in similar plants around the region.

BPA began to explore a program to help modernize the Northwest's large aluminum smelters and thus conserve electricity by improving the efficiency of their power use.

Scientist strive to rebuild salmon and steelhead runs in a series of projects funded by BPA.

For the fourth straight year, BPA signed cooperative agreements to provide technical assistance to local governments and to consumers at a total cost of some $2.7 million. It also awarded $450,000 worth of grants to 10 local governments seeking to develop new approaches to energy savings. And BPA contracted with the Oregon Museum of Science and Industry to offer workshops and new educational curricula to primary and secondary school teachers in the Northwest.

Each Project Evaluated

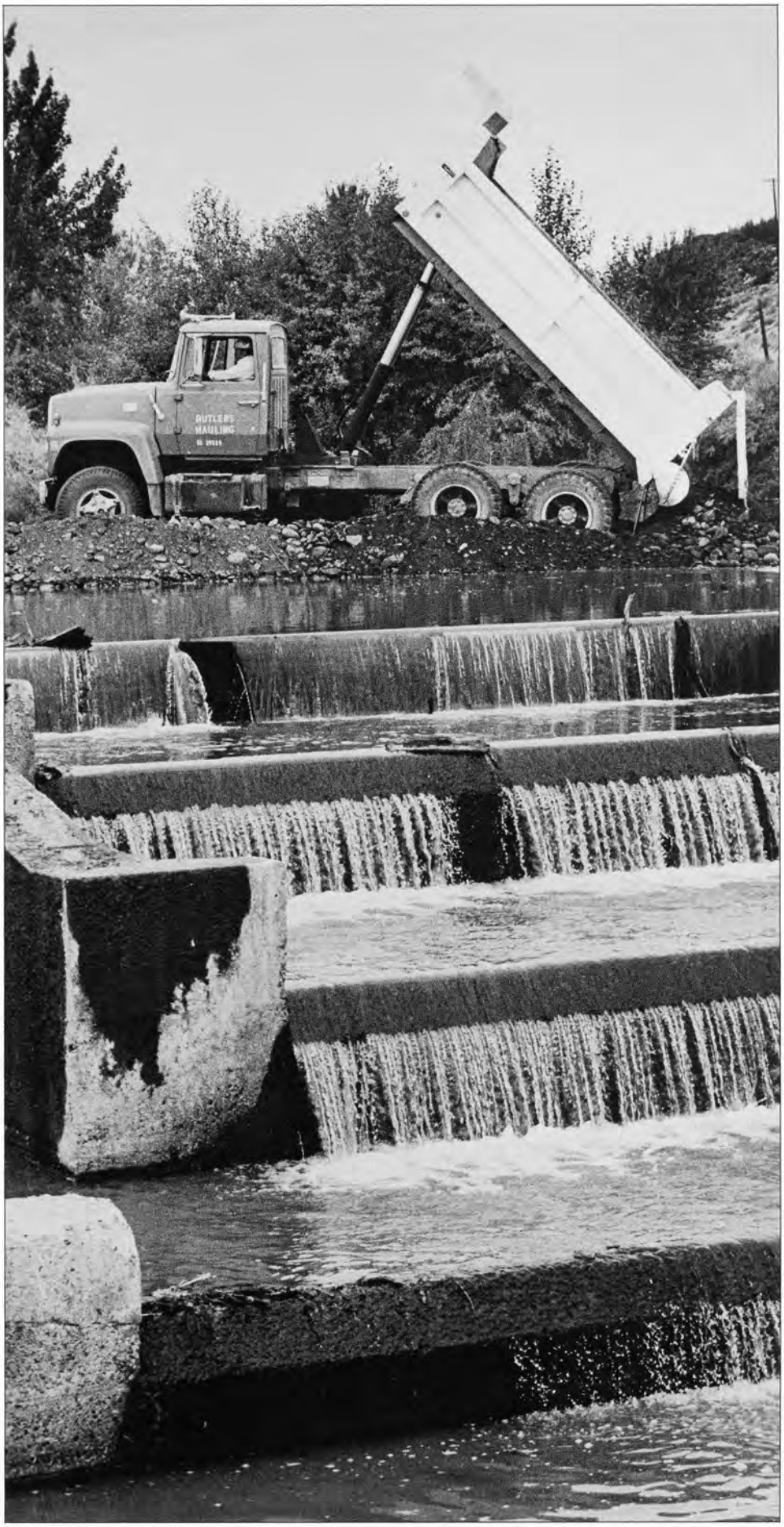
BPA checks on the effectiveness of its conservation programs. Each individual program is evaluated—in an organized, documented, scientific way—as it progresses. The aim is to make certain each dollar spent produces worthwhile results. Some 35 such evaluations are currently under way.

Tide Turns for Fish and Wildlife

The outcome of the fight to save the Pacific Northwest's salmon and steelhead is still in doubt. But the tide of battle may be turning in favor of the fish.

Early this year, a BPA biologist, speaking with conviction, summed up the situation in this way:

"We are now at a low point. We have 10 percent of the fish we had 100 years ago. But we are also at a turning point. We now have the mechanism to bring back our fish in a way that has never been done before in the world."



A new fish ladder is part of the effort to rebuild the Yakima River's salmon and steelhead runs.

BPA's role in this effort expanded in 1980 when the Pacific Northwest Power Act was passed. In the past, BPA had helped pay for fish facilities at the Federal dams and for research and development work—within certain authorized limits. The Act gave BPA new responsibilities. Today BPA works closely with the Northwest Power Planning Council, hydroelectric dam operators, Federal fish and wildlife agencies, State fisheries agencies, and Indian tribes.

The law limits BPA's role to repairing and mitigating the damage done to fish and wildlife by Columbia Basin hydroelectric projects. To achieve this objective, BPA in 1985 funded 142 contracts, 120 of which were existing and 22 of which were new. They included:

- 33 projects to enhance passage and increase wild fish runs.
- 3 projects to protect upriver fish.
- 5 projects to restock natural runs with hatchery fish through low-cost production facilities, habitat surveys, and acclimation ponds.
- 11 projects to increase the number of fish produced at existing hatcheries.
- 20 projects to protect downstream migrants.
- 5 projects to measure and make up for wildlife losses caused by dams.
- 12 projects to lessen the impact of hydroelectric operations on sturgeon and upriver game fish.
- 13 projects to assess the impacts of small hydroelectric projects on critical fish habitat.
- 16 projects in the Yakima Valley to provide safe passage past irrigation dams and canals.

A steel grid covers a new Yakimia River fish ladder and deters poaching.

About half of the $25.5 million BPA spent on fish projects in 1985 went to build passage facilities, improve habitat, and construct propagation facilities.

BPA and Washington Water Power Co. contributed equally toward a kokanee salmon hatchery on Lake Pend Oreille. The hatchery was completed in November 1985, 1 year ahead of schedule. It will produce 20 million kokanee a year. The Idaho Fish and Game Department will operate the hatchery.

BPA is funding a number of projects in the Yakima River Basin where a large salmon fishery once flourished and now has all but disappeared.

One of these is a set of newly installed, rotating fish screens at Sunnyside irrigation dam. Recent studies indicate that 100 percent of the young salmon and steelhead that reach the screens get past them safely.

A new fish ladder on the right bank at Sunnyside Dam was completed in April 1985. It is also operating effectively. Construction is under way on a new ladder for the left bank.

A screen and ladder is being installed on Toppenish Creek near Satus, and screens are going in at the Wapato and Richland canals. These projects will be completed in 1986.

Research Expands

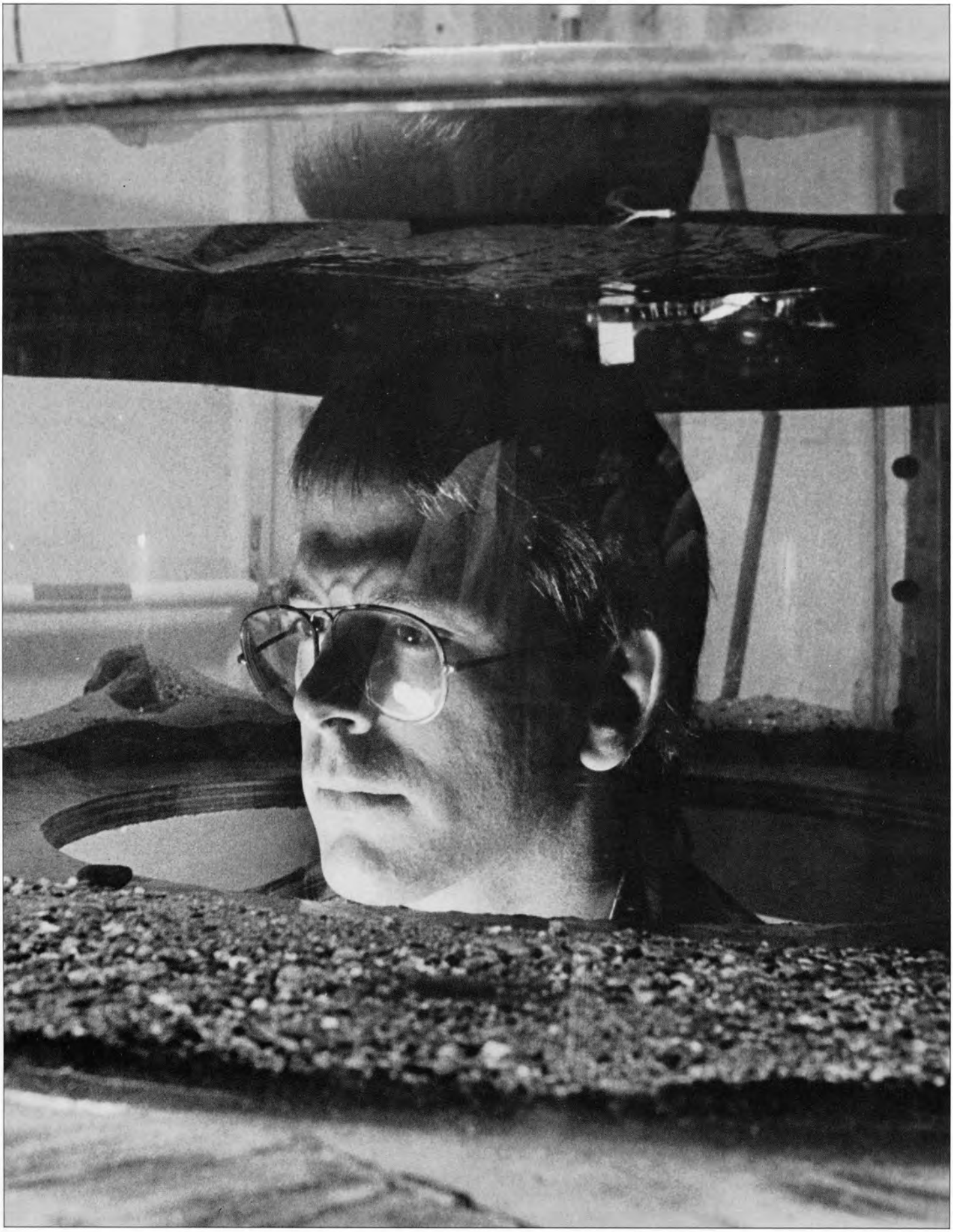
About 38 percent of the 1985 expenditures for fish went for research, assessments, and support functions.

Researchers are implanting young fish with computer chips—passive integrated transponders—whose tiny antennae send signals that help scientists identify individual fish as they migrate to and from the ocean. Each signal carries a number identifying the fish and its origin. Scientists will test the tagged fish for 1 more year before they decide whether to employ this new tool on a wide basis.

Little is known about sturgeon or how their behavior was affected by the dams that blocked their migratory routes. Now a new study is gathering information on their life history. Young sturgeon in particular are being studied for their response to such things as changes in water temperature, flow, and other variables. Information from these studies will be used to help sturgeon survive in an environment that has been altered by man.

Researchers are developing a one-day test that hatchery managers can use to detect five major diseases in returning adult salmon and steelhead before spawning the fish. By eliminating the eggs and milt of infected fish, workers can eliminate a major source of diseased hatchery fish.

A doughnut shaped tank allows a researcher to analyze the mysterious behavior of young sturgeon.



Researchers are also examining ways, other than by destroying eggs, to stop the spread of infections. The study leaders seek to block passage of viruses from diseased female fish to their offspring.

Biologists are also studying the nutritional needs of young salmon and steelhead. They plan to formulate fish foods that will produce fish that are healthier and more resistant to disease and stress.

Biologists are also weighing the threat that predatory fish pose to young salmon. Reservoirs on the rivers have created new habitat for predatory fish, and this has increased their numbers. The biologists are gathering new information on location, feeding times and the extent of predation. Their report will present mechanical and biological alternatives for predator control.

A Friendly Boost

Twelve percent of the fishery money was spent to help tens of millions of young salmon and steelhead migrate downstream to the Pacific Ocean. Every spring these young fish leave the hatcheries and spawning beds and start their long journey to the sea. For millenia, the spring runoff from melting snows unfailingly swept them along. But beginning in the 1930s, the annual runoffs were checked by dams built to generate electricity—with disastrous effects on smolt migrating to the ocean. In some recent years, less than 10 percent of the young fish reached the sea.

This situation began to change in 1984, the first year an allocation of water was saved for the fish and released to the Snake and Columbia rivers to help move the fish downstream. The 1985 migration of young fish bound for the ocean was the largest in 10 years—and it came in an unusually dry year. The water releases work.

Where the Money Goes

Eighty percent of BPA's total expenditures in 1985 for fish and wildlife was spent on anadromous fish, 14 percent on resident fisheries, 3 percent on wildlife, 1 percent to assess proposed hydro projects, and 2 percent to help determine the extent of BPA's future obligation toward fish and wildlife.

Saving Sheep from Extinction

One of the more interesting projects during 1985 took place on the ridges northeast of the reservoir behind Libby Dam, a Federal project in Montana. There biologists of the Kootenai National Forest and the Montana Department of Fish, Wildlife and Parks, working with BPA funds, are attempting to save a small band of rare mountain sheep from extinction.

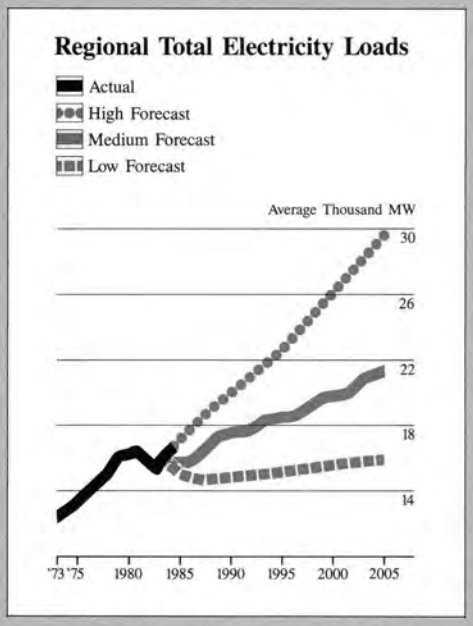
These sheep are called the Ural-Tweeds. They once roamed the Rocky Mountains from Canada to western Montana. When Libby Dam was built and its reservoir flooded 12,000 acres of their last remaining habitat, there were 200 Ural-Tweeds left. The impact of the dam reduced their numbers to 25.

Two BPA projects are attempting to rebuild and improve the ridges above the lake by clearing away unwanted trees and reseeding grass on the slopes. The biologists watch the sheep closely to measure the results. Because the sheep now have a winter range and the ewes find better spring forage, the tiny flock is growing in number.

The 1985 Load Forecast

BPA's annual 20-year load forecast for the Pacific Northwest continues to project a relatively low rate of growth in the use of firm power.

The medium case forecasts an average annual rate of growth of 1.5 percent for the years 1985 to 2005. Last year the 1984 medium forecast for 1984-2004 averaged 1.6 percent.



The forecast has three levels: low, medium and high. There is a 10 percent chance the high level will be exceeded, a 10 percent chance the actual low will be below the low level, and an 80 percent chance that the actual load will fall between the low and high levels.

The comparative forecasts in megawatts for 1985, 1990, 1995, 2000 and 2005 are:

	1985	1990	1995	2000	2005
High	16,737	19,942	22,635	25,869	28,812
Medium	15,957	17,818	18,911	20,187	21,409
Low	15,329	14,977	15,322	15,721	16,059

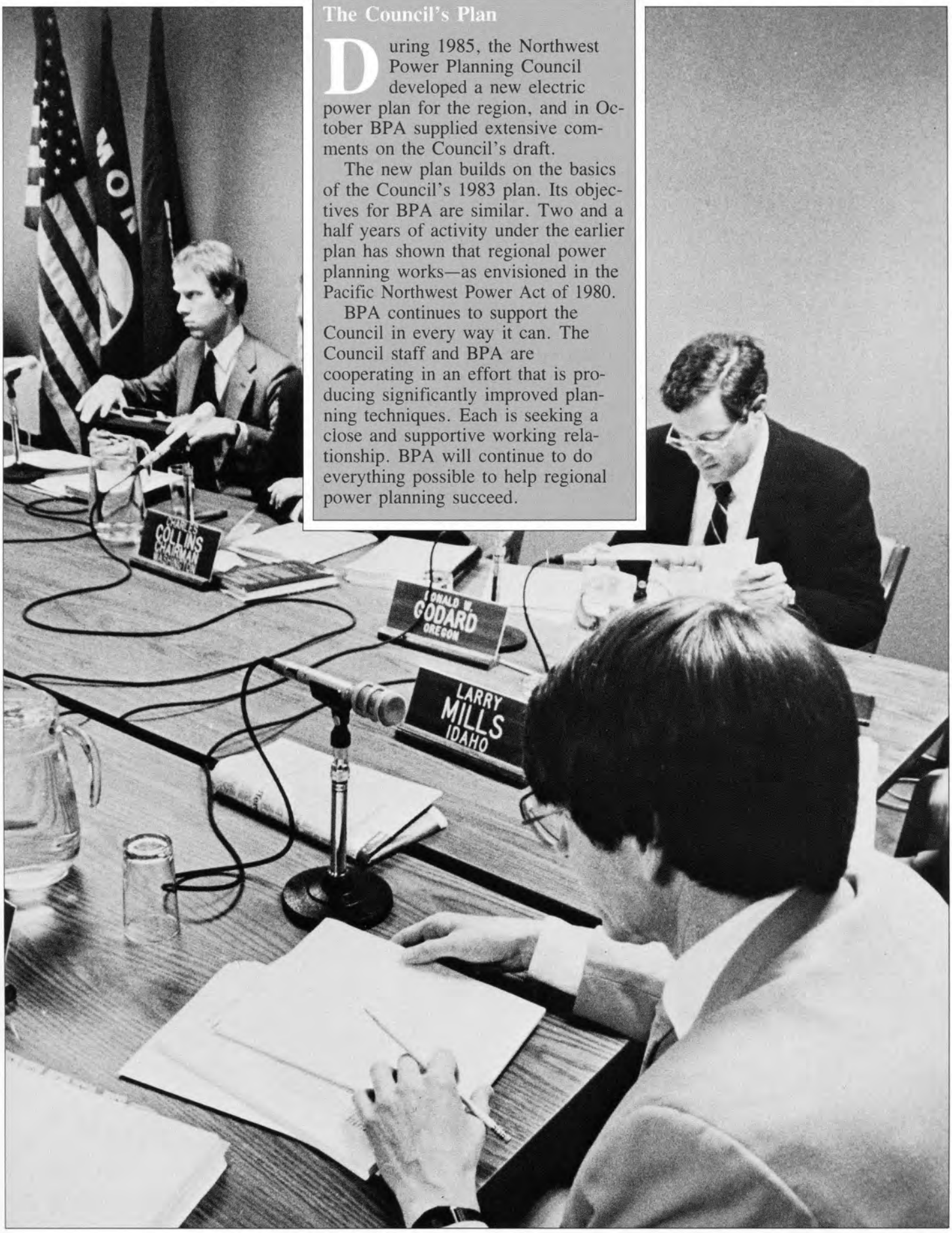
BPA forecasts are used for resource planning, the Pacific Northwest Coordination Agreement submittal, and for BPA rate cases to analyze the impact of alternative rate designs and levels on BPA's forecasted revenues.

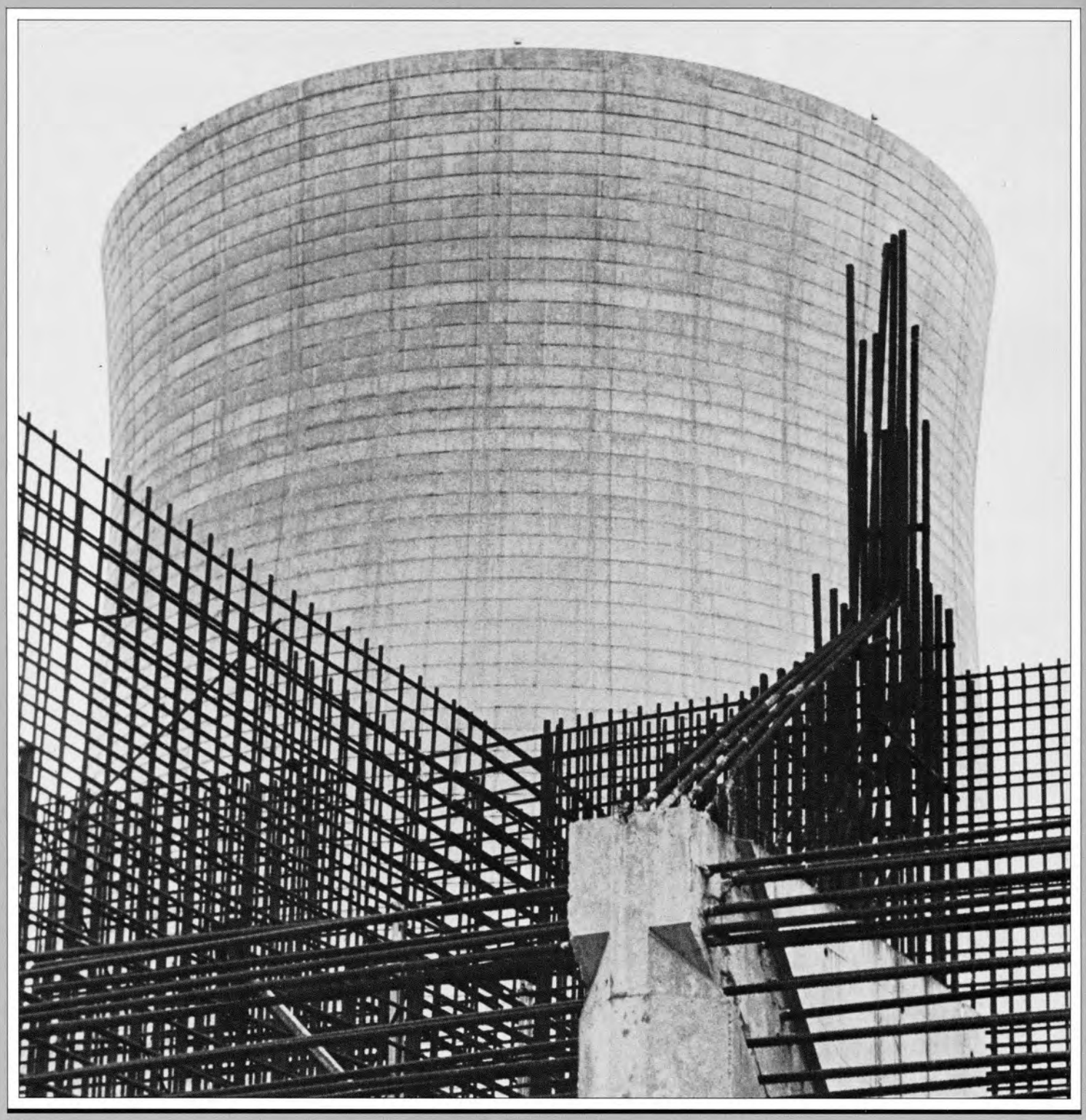
The Council's Plan

During 1985, the Northwest Power Planning Council developed a new electric power plan for the region, and in October BPA supplied extensive comments on the Council's draft.

The new plan builds on the basics of the Council's 1983 plan. Its objectives for BPA are similar. Two and a half years of activity under the earlier plan has shown that regional power planning works—as envisioned in the Pacific Northwest Power Act of 1980.

BPA continues to support the Council in every way it can. The Council staff and BPA are cooperating in an effort that is producing significantly improved planning techniques. Each is seeking a close and supportive working relationship. BPA will continue to do everything possible to help regional power planning succeed.





Shortly before the fiscal year ended, the principal parties in a lawsuit over Washington State Nuclear Plant 3 agreed to settle the suit out of court.

The proposed settlement brightens BPA's financial outlook. It seeks to avoid a BPA rate increase of as much as 20 percent that might have to go into effect if BPA were to lose the case. It also seeks to avoid costly legal expenses and years of litigation.

The suit grew out of a decision made in May 1983. The Washington Public Power Supply System, acting on a recommendation from BPA, suspended construction of WNP-3 for up to 3 years, a time period that was later extended indefinitely.

The decision was based on the fact that: (a) prudent financing to finish the project was not available and (b) the power the plant would produce will not be needed before the mid-1990s. Had BPA decided to complete the plant out of current revenues, it would have had to raise its rates by about 20 percent.

Subsequently, the four private utilities who own 30 percent of WNP-3—Pacific Power & Light, Portland General Electric, The Washington Water Power Co., and Puget Sound Power & Light—filed a suit in the U.S. District Court in Seattle saying BPA and the Supply System had breached their contract to complete the plant. They later filed damage claims against BPA totaling more than $2 billion.

In mid-1984, BPA and the four utilities, recognizing that prolonged, costly litigation would be detrimental to the region, began to explore a settlement. During the discussions that followed, the parties agreed on a general framework. By the following spring, they had agreed on the broad terms, and in April 1985 BPA made public a package of materials on the proposal. In May, BPA followed with an environmental assessment.

WNP-3: Reinforcement bars dominate scene at unfinished nuclear plant.

While the proposal was being widely discussed throughout the region, BPA took specific steps to solicit further comment and broaden public power participation in the process. BPA had tried to keep the public utilities and other interested groups and individuals fully informed. But a number of these utilities were suggesting changes and asking to participate in the negotiations. It was then that representatives of several major public utilities began meeting with the four private utilities and BPA. Their participation led to at least eight major changes that were incorporated into the proposal and released for further public comment.

Meanwhile, however, the settlement was being vigorously opposed by a another group of public utilities. They consisted mainly of about a dozen large public utilities in Washington State who declined to take part in the negotiations.

Nonetheless, the parties proceeded and an agreement was signed. The settlement agreement was signed on September 17 after BPA's public involvement and environmental processes were concluded. It was reviewed by the U.S. Department of Energy, approved by the U.S. Justice Department, and presented to Federal Judge William Browning in Seattle on September 20.

The agreement is expected to have little or no effect on BPA's rates to either its public utility or industrial customers. Moreover, the heads of the four private utilities have sent letters to BPA, saying the long-term effect, if any, of the proposal on their ratepayers should not be substantial.

Judge Browning has since issued two rulings on pleadings entered by the opposing utility group. He denied a motion that would have compelled BPA to mediate the settlement agreement. He did permit the opposing group to challenge the agreement and allowed 90 days for the submission of briefs. As the calendar year came to an end, the challenge was still not resolved.

If the settlement goes forward, the private utilities will purchase about the same amount of power from BPA that they would have received from their share of the investment in WNP-3. And they will pay to BPA about the same amount of money for the power that they would have paid for WNP-3 power.

BPA has agreed to furnish the utilities an average of 193 megawatts for about 30 years. The power would come primarily from BPA's sizeable surplus of power. BPA will guarantee firm delivery of the power and, if need be, will be permitted to use combustion turbines owned by the four utilities to firm up deliveries.

In exchange, BPA will receive some $700 million from the utilities—or about 24 mills per kilowatthour—in operation and maintenance payments. BPA also is permitted to acquire the private utilities' share of the plant's capability, valued at about 5 mills per kilowatthour.

To date, the investor-owned utilities have spent approximately $805 million in capital costs for their 30 percent share of the project. All of this equity would be available to BPA at no additional cost.

A careful analysis by BPA indicates the proposed settlement would result in $132 million worth of net benefits to BPA over the life of the agreement.

This estimate of net benefits is based on probabilities and is, of course, an educated guess. There is a risk that BPA will lose money, but it is not great, and the risk is acceptable when weighed against the possibility of a major increase in the electricity rates for Northwest ratepayers.

Management's Discussion and Analysis of Financial Condition

Results of Operations

Positive financial results were attained in fiscal year (FY) 1985, and FY 1984. Net Revenues were nearly the same for FY 1985 and FY 1984. The Net Revenues for both years were substantially higher than in FY 1983 due primarily to timely rate action, and significant success in marketing surplus power and controlling costs.

Operating Revenues

Rate Actions BPA has achieved stable rates. During the period December 20, 1979, through November 1, 1983, preference customer rates had four substantial increases. Effective July 1, 1985, preference customer rates were increased an average of less than 1 percent.

Other significant actions taken to ensure the financial integrity of the Federal Columbia River Power System (FCRPS) included offering special incentive rates to direct service industries, enabling these important customers to keep doing business at a time when the world price for their products were at record lows.

Furthermore, the standard industrial rate dropped from 2.49 to 2.28 cents per kWh. At the same time the standard rate for nonfirm energy sales was increased from 1.85 to 2.34 cents per kWh to acknowledge the Federal Energy Regulatory Commission (FERC) decision that insufficient costs were included in nonfirm rates. Revenues from surplus firm power and surplus energy increased from $26 million in FY 1983 to $112.2 and $239.5 million in FY 1984 and FY 1985, respectively.

Operating Expenses

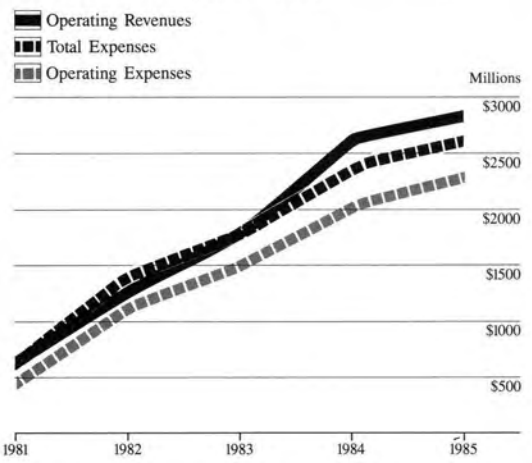
BPA Operation and Maintenance BPA's operation and maintenance expenses were reduced over $40 million from the rate case projections. These savings were achieved mainly in system maintenance; system operation; resource planning, acquisition and oversight; and fish & wildlife.

Depreciation The method for computing depreciation on completed utility plant was changed from compound interest to straight-line in FY 1985. This required restating the FY 1984 depreciation to the straight-line method so the two years are consistent. The change resulted in $39.4 and $49.9 million additional depreciation expense for FY 1984 and FY 1985, respectively.

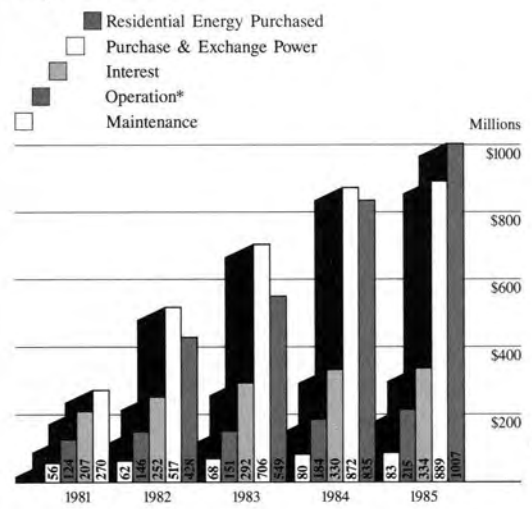
This change was made because the straight-line method is an acceptable method under generally accepted accounting principles (GAAP) whereas the compound interest method is not. As a result the FCRPS financial statements are now presented in accordance with GAAP. The new presentation will enable easier analysis and comparison with other utilities.

Interest Expense Interest on borrowings was reduced $36.9 million from the rate case projections. This savings was achieved through a combination of delayed borrowing and maintaining lower debt levels than projected.

Revenue and Expense Trend



Expense Trend



Basis for Financial Reporting

BPA prepares financial statements for the FCRPS to report its financial condition as if it were a public utility.

The financial statements are audited by the firm of Arthur Andersen & Co., independent public accountants in accordance with generally accepted auditing standards. The financial statements with the auditors' report appear on pages 34 through 47.

Power rates are based on the FCRPS Revenue Requirement Study. While the financial statements show historical results, the Revenue Requirement Study shows projected costs to be recovered from rates. The Revenue Requirement Study considers BPA's obligation to recover costs and sets a revenue level sufficient to meet those obligations. Costs include operation and maintenance; purchase and exchange power; interest and recovery of the FCRPS investment in power generating, conservation, and transmission facilities. The two sets of financial reports measure different things; historical results in the financial statements and projected obligations in the Revenue Requirement Study.

Revenue Requirement Study

The Revenue Requirement Study, which includes demonstrated repayment of Federal investment, reflects revenues and costs from the 1985 Wholesale Power and Transmission Rate Proceedings. On June 28, 1985, FERC approved the proposed rate increases on an interim basis.

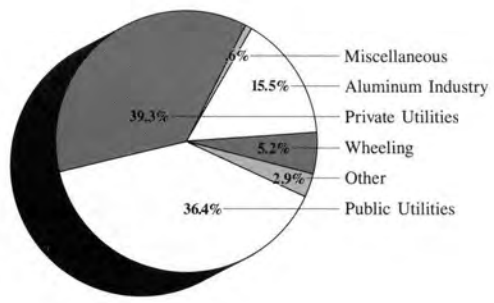
Repayment Demonstration BPA is required by PL 89-448 to demonstrate that the reimbursable costs of the FCRPS are scheduled to be returned to the U.S. Treasury from BPA net revenues within the period prescribed by law. BPA is required to make a similar demonstration for the costs of irrigation projects which are beyond the ability of the irrigation water users to repay. These requirements are met by conducting a Revenue Requirement Study.

In 1985, BPA prepared separate Revenue Requirement Studies for generation and transmission in accordance with an order issued by FERC on January 27, 1984, 26 FERC ¶61,096.

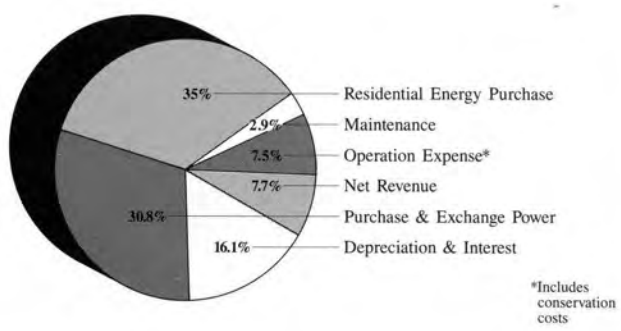
Repayment Obligation BPA's rate schedules must be designed to collect enough revenue to return the reimbursable costs of each FCRPS investment and each irrigation assistance obligation within the time fixed by law for the investment. In the absence of a specific legislated period, the reimbursable costs must be returned within 50 years from the date the investment is capable of producing revenue or within the investment's average service life, whichever is less. If existing rates are not likely to meet this requirement, BPA must take action to adjust its rates.

Whether the Federal investment is repaid within the time allowed can be shown by comparing the unrepaid investment resulting from BPA's repayment schedule with the allowable unrepaid investment resulting from a "term schedule" on a year-by-year basis. A term schedule represents a repayment schedule whereby each investment would be repaid in total in the year it was due.

1985 Sources of Revenue



1985 Disposition of Revenue



The reporting requirements of PL 89-448 are met as long as the unrepaid FCRPS investment and irrigation assistance resulting from BPA's repayment schedule is less than or equal to the allowable unrepaid investment. Although the comparison is illustrated by graphs representing total FCRPS generation and total FCRPS transmission investment, the actual comparison is performed on an investment by investment basis.

Repayment of FCRPS Investment The graphs of Unrepaid Federal Generation and Transmission investment illustrate that the unrepaid investment resulting from BPA's generation and transmission repayment schedules is always less than the allowable unrepaid investment. This shows that BPA's current rates are scheduled to recover all reimbursable costs of FCRPS investments on or before their due dates.

The *term schedule* lines in the graphs show how much of the investment can remain unpaid in accordance with the repayment period for the generation and transmission components of the FCRPS. The *BPA repayment schedule* lines show how much of the investment remains to be repaid according to BPA's repayment schedules. In each year, BPA's repayment schedule is ahead of the term schedule.

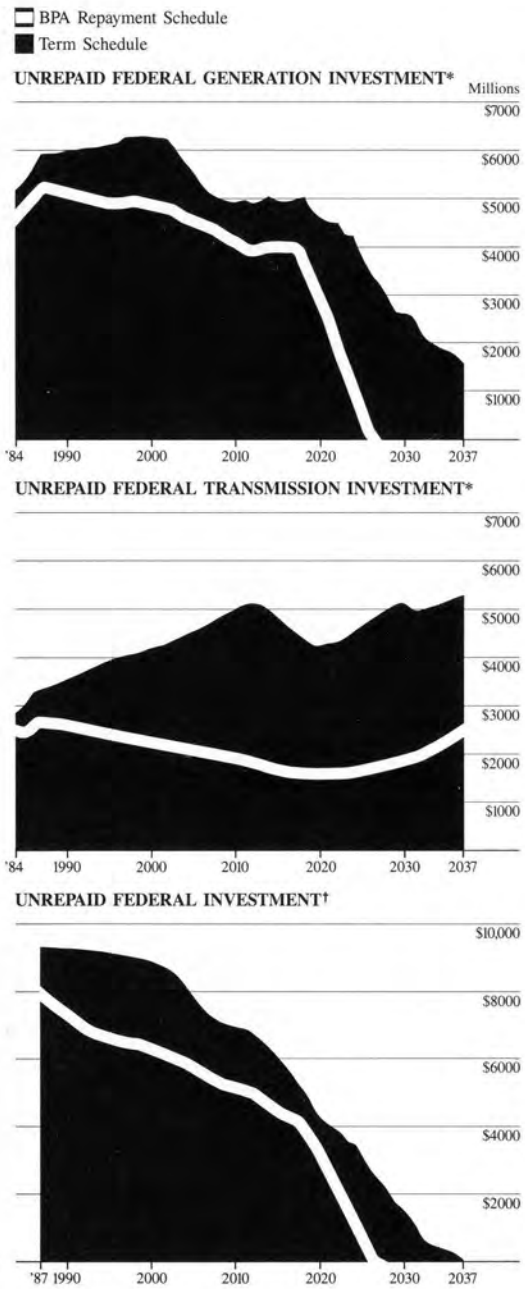
This occurs because BPA plans repayment both to comply with investment due dates and to minimize costs over the 50 year repayment period. Costs are minimized by repaying highest interest bearing investment first, to the extent possible. This will result in some investments being repaid before their due dates, while assuring that all other investments will be repaid by their due dates.

The graphs include the costs of replacements necessary to maintain the FCRPS generation and transmission facilities.

The Unrepaid Federal Investment graph displays the total planned unrepaid FCRPS investment compared to allowable total unrepaid FCRPS investment omitting replacements. This shows that the FCRPS investment through FY 1987 is scheduled to be returned to the U.S. Treasury within the 50 year repayment period and ahead of due dates.

Repayment of Irrigation Assistance BPA plans to meet irrigation assistance obligations in the year they are due over the next 50 years. It is Federal policy that BPA will pay irrigation assistance on or before due dates until the entire irrigation assistance obligation has been met.

Repayment Period
Federal Columbia River Power System
Fiscal Year 1987
Ending September 30



*Includes future replacements

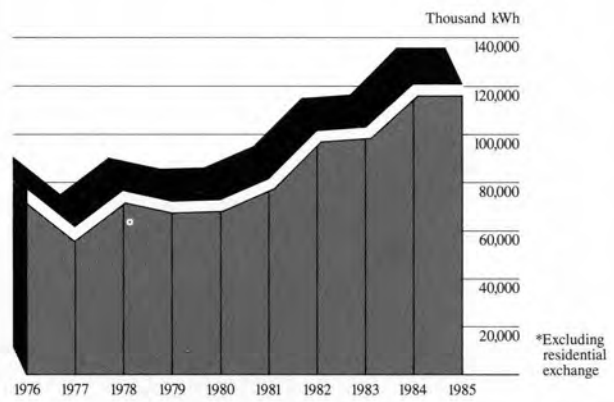
†Includes generation and transmission investments through fiscal year 1987. Excludes future replacements.

Because BPA has scheduled repayment of irrigation assistance obligations in the year they are due, the planned unrepaid irrigation assistance is exactly equal to the allowable unrepaid irrigation assistance.

Repayment Policy BPA's repayment policy is used to determine its revenue requirements and rate levels. This policy, based on the Department of Energy's interpretation of laws and regulations, requires that FCRPS revenues be sufficient to:

1. Pay the cost of obtaining power through purchase and exchange agreements.
2. Pay the cost of operating and maintaining the power system.
3. Pay interest on and repay the outstanding revenue bonds sold to the U.S. Treasury to finance transmission system construction.
4. Pay interest on the unrepaid investment in power facilities financed with appropriated funds (Federal hydroelectric projects are all financed with appropriated funds, as were BPA transmission facilities constructed before 1978).
5. Pay, with interest, any outstanding deferral.
6. Pay the power investment in each Federal hydroelectric project within 50 years after it goes into service (except for the Chandler Project, which has a legislated repayment period of 66 years).
7. Pay each increment of the investment in the BPA transmission system financed with appropriated funds within the average service life of the transmission facilities 45 years).
8. Pay each increment of financing for conservation within the benefit period (20 years).
9. Pay the investment in each replacement at a Federal hydroelectric project within its service life (investments bearing the highest interest rate will be paid first to the extent possible while still completing repayment of each increment of investment within its prescribed repayment period).
10. Pay construction costs at Federal reclamation projects which are beyond the ability of the irrigation water users to pay, and which are assigned for payment from commercial power revenues, within the same period available to the water users for making payments. These periods range from 40 to 66 years with 60 years being applicable to most of the irrigation payment assistance.

Kilowatt Hours Sold by Fiscal Year*



Electric Energy Account *Table I*

Fiscal Year 1985

Energy Received (Millions of kilowatt hours)	
Energy Generated for BPA (Excludes Residential Exchange)	
Bureau of Reclamation	19,486
Corps of Engineers	58,008
WNP No. 2	4,843
Hanford Steamplant (NPR)	3,933
Centralia Thermal Project	580
Trojan Nuclear Plant	1,959
Other Generation	639
Power Interchanged In	64,986
Total Received	154,434
Energy Delivered (Millions of kilowatts hours)	
Sales (1)	83,749
Power Interchanged Out	67,039
Used by Administration	63
Total Delivered	150,851
Energy Transmission Losses	3,583
Total	154,434
Losses as Percent of Total Received	2.3%
Maximum demand on generation (kilowatts)	18,603

(1) Based on actual billings. Excludes residential exchange and accounting accruals.

Generation by the Principal Electric Utility Systems of the Pacific Northwest (1) *Table 2*
Fiscal Year 1984

Utility	MWH	Per Cent of Total
Publicly Owned:		
Federal Columbia River Power System (2)	90,900	50.1
Grant County PUD	3,400	1.9
Chelan County PUD	2,900	1.6
Seattle City Light	7,000	3.9
Douglas County PUD	800	0.4
Tacoma City Light	2,700	1.5
Eugene Water and Electric Board	600	0.3
Pend Oreille County PUD	500	0.3
Total Publicly Owned	108,800	60.0
Privately Owned		
Pacific Power and Light	19,600	10.8
Idaho Power Company	16,200	8.9
Montana Power Company	7,700	4.3
Portland General Electric	11,200	6.2
Washington Water Power Company	6,800	3.7
Puget Power and Light Company	11,100	6.1
Total Privately Owned	72,600	40.0
Total Generation	181,400	100.0

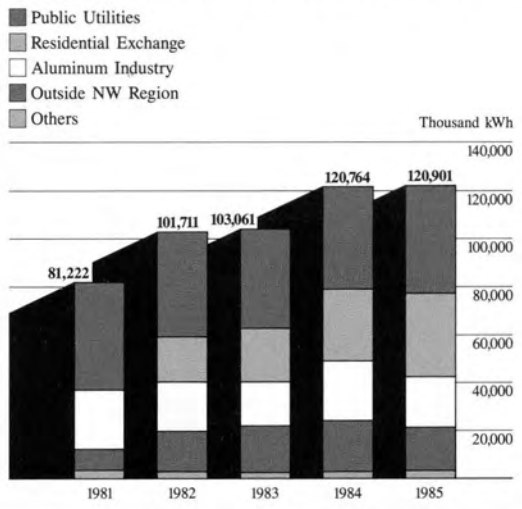
(1) Generation shown is for members of the Northwest Power Pool plus Pend Orielle County PUD and the Washington Public Power Supply System. Utah Power & Light Co., British Columbia Hydro and Power Authority, West Kootenay Power and Light and Trans Alta Utilities, who are members of the Power Pool, are not included because their service areas are outside the Pacific Northwest.

(2) Includes: Pacific Northwest generating facilities of the Bureau of Reclamation and Corps of Engineers; Washington Public Power Supply System's nuclear plant (WNP-2), Hanford steam plant (NPR), and Packwood hydro plant; the Okanogan PUD share of Wells; the municipality shares (Forest Grove, McMinnville, and Milton-Freewater) of Priest Rapids and Wanapum; the Kittitas PUD share of Priest Rapids; the Snohomish PUD share of the Centralia steam plant and the Jackson hydro plant; the federal share of the Trojan nuclear plant; the Pacific NW Generating Companies' share of Boardman; the PGE Kinzua co-generation project; the Clark County PUD-Great Western Malting co-generation project; and the Seattle City Light and Tacoma City Light shares of Southern Columbia Basin Irrigation hydro generation.

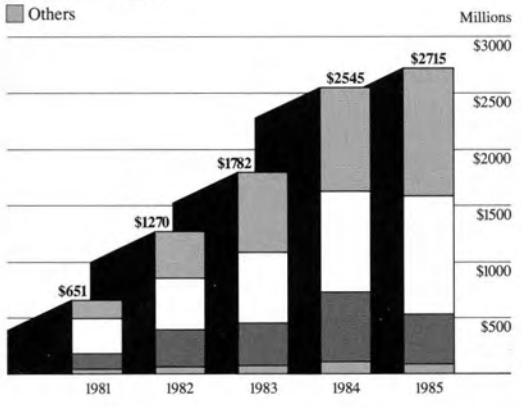
Sales of Electric Energy ($000) *Table 3*

Customer	Capacity Sales		Energy Sales	
Northwest Region Municipalities	MW	Revenue	MWH	Revenue
Albion, ID	8	$ 32	3,359	$ 51
Ashland, OR	289	1,159	130,466	1,960
Bandon, OR	117	473	48,961	732
Blaine, WA	95	388	43,267	655
Bonners Ferry, ID	95	392	32,939	514
Burley, ID	220	881	106,539	1,602
Canby, OR	236	969	99,812	1,506
Cascade Locks, OR	62	244	27,253	409
Centralia, WA	333	1,358	120,537	1,837
Cheney, WA	212	864	99,402	1,497
Cons. Irrig. Dist., WA	6	21	1,563	23
Coulee Dam, WA	34	153	16,985	259
Declo, ID	7	28	2,904	44
Drain, OR	39	146	18,303	270
Eatonville, WA	40	162	16,806	254
Ellensburg, WA	314	1,241	152,141	2,292
Eugene, OR	2,652	10,315	1,608,317	24,062
Fircrest, WA	98	397	43,088	650
Forest Grove, OR	167	592	81,127	1,231
Heyburn, OR	147	575	79,655	1,201
Idaho Falls, ID	1,136	4,673	541,980	8,199
McCleary, WA	84	328	34,763	521
McMinnville, OR	604	2,316	293,500	4,394
Milton, WA	80	325	35,154	531
Milton-Freewater, OR	92	257	29,606	458
Minidoka, ID	2	9	1,093	16
Monmouth, OR	118	493	51,014	768
Port Angeles, WA	1,092	4,316	595,035	8,962
Richland, WA	1,218	4,955	538,876	8,098
Rupert, ID	171	705	77,422	1,168
Seattle, WA	1,574	6,376	2,416,775	34,126
Springfield, OR	1,335	5,390	669,356	10,046
Steilacoom, WA	91	379	39,642	601
Sumas, WA	18	73	8,408	126
Tacoma, WA	4,110	14,996	3,307,909	51,435
Vera Irrig. Dist., WA	322	1,335	142,816	2,152
WPPSS, WA	380	1,482	80,611	1,196
Total Municipalities (37)	17,598	$68,798	11,597,384	$173,846

Kilowatt Hours Used by Customer Class



Revenues by Customer Class



Customer	Capacity Sales		Energy Sales	
Public Utility Districts	MW	Revenue	MWH	Revenue
Benton Co.	2,936	$ 11,316	1,354,170	$ 19,917
Central Lincoln	2,235	8,821	1,211,771	18,128
Chelan Co.	480	663	281,112	3,648
Clallam Co.	916	3,126	393,497	4,959
Clark Co.	4,750	19,927	2,453,213	37,080
Clatskanie	1,265	4,744	775,929	11,594
Columbia River	371	1,542	191,515	2,806
Cowlitz Co.	4,477	16,883	3,103,990	46,040
Douglas Co.	374	170	16,598	107
Emerald	798	2,914	340,550	4,754
Ferry Co.	125	462	61,782	857
Franklin Co.	1,220	4,630	576,301	8,536
Grant Co. #2	1,129	723	109,103	940
Grays Harbor	2,059	8,260	1,087,178	16,333
Kittitas Co.	67	235	28,611	401
Klickitat Co.	512	1,864	234,166	3,222
Lewis Co.	1,125	4,083	633,629	8,547
Mason Co. #1	115	439	52,783	737
Mason Co. #3	868	3,538	382,317	5,717
Northern Wasco Co.	459	1,866	199,296	3,000
Okanogan Co.	364	1,617	309,713	4,691
Pacific Co. #2	483	1,952	216,671	3,268
Pend Orielle Co.	2	5	(6,898)	(8)
Skamania Co.	222	846	99,307	1,389
Snohomish Co.	8,464	34,826	3,823,341	57,457
Tillamook	658	2,686	291,511	4,365
Wahkiakum Co.	75	291	34,446	484
Whatcom Co.	223	838	139,688	2,093
Total Public Utility Districts (28)	36,772	$139,267	18,395,290	$271,062

Customer	Capacity Sales		Energy Sales	
Cooperatives	MW	Revenue	MWH	Revenue
Alder Mutual Light	5	$ 17	1,982	$ 29
Benton Rural Elec. Assn.	605	2,159	284,668	4,132
Big Bend Coop.	746	2,126	388,762	5,242
Blachly-Lane Coop.	243	912	107,548	1,561
Central Elec. Coop.	583	2,173	272,495	3,871
Clearwater Power Co.	298	1,118	135,071	1,939
Columbia Basin Coop.	226	765	112,530	1,512
Columbia Power Coop.	56	185	25,590	353
Columbia Rural Elec. Assn.	370	1,040	184,013	2,389
Consumers Power	602	2,311	282,135	4,055
Coos-Curry Elec. Coop.	469	1,626	236,775	3,178
Douglas Elec. Coop.	234	874	113,331	1,638
East End Mutual Elec.	33	124	14,838	218
Elmhurst Mutual P&L	462	1,892	203,264	3,076
Fall River Elec. Coop.	270	931	119,616	1,683
Farmers Elec. Co.	10	41	4,268	64
Flathead Elec. Coop.	283	1,070	134,737	1,880
Glacier Elec. Coop.	314	1,183	170,927	2,430
Harney Elec. Coop.	223	746	121,374	1,621
Hood River Elec. Coop.	174	697	83,084	1,258
Idaho Co. L&P Coop.	68	261	31,373	438
Inland P&L	1,019	3,927	459,376	6,433
Kootenai Elec. Coop.	374	1,388	173,159	2,414
Lakeview L&P	483	1,932	237,713	3,580
Lane Elec. Coop.	507	1,981	224,534	3,206
Lincoln Elec. Coop. - MT	151	561	69,859	977
Lincoln Elec. Coop. - WA	213	592	113,734	1,570
Lost River Elec. Coop.	112	345	59,533	781
Lower Valley P&L	741	2,802	361,279	5,161
Midstate Elec. Coop.	424	1,530	201,438	2,748
Missoula Elec. Coop.	242	903	116,947	1,627
Nespelem Valley Elec. Coop.	85	321	38,604	549
Northern Lights	408	1,520	208,838	2,917
Ohop Mutual Light Co.	82	315	34,564	495
Okanogan County Coop.	59	228	27,925	401
Orcas P&L	240	904	106,893	1,501
Pacific NW Generating Co.	0	0	1,971	30
Parkland Light & Water	214	868	99,987	1,513
Peninsula Light Co.	765	3,157	323,981	4,901
Prairie Power Coop.	17	57	8,407	102
Raft River Elec. Coop.	306	826	182,986	2,445
Ravalli Elec. Coop.	160	603	75,168	1,039
Riverside Elec. Co.	30	118	13,551	200
Rural Elec. Co.	176	681	81,681	1,163
Salem Elec.	555	2,266	262,377	3,960
Salmon River Coop.	360	1,283	212,376	3,094
South Side Elec. Lines	77	255	34,258	456
Surprise Valley Elec.	219	707	108,292	1,400
Tanner Elec.	60	230	25,369	356
Umatilla Elec. Coop.	1,014	3,232	587,560	8,270
Unity P&L	130	473	60,597	822
Vigilante Elec. Coop.	256	811	116,673	1,578
Wasco Elec. Coop.	251	946	107,264	1,495
Wells Rural	204	705	106,263	1,470
West Oregon Coop.	127	477	57,882	807
Total Cooperatives (55)	16,335	$59,195	7,929,420	$112,028

Customer	Capacity Sales		Energy Sales	
Federal Agencies	MW	Revenue	MWH	Revenue
U.S. Department of Energy	946	$3,599	531,838	$ 7,943
U.S. Bureau of Mines	16	65	5,922	89
U.S. Air Force	64	245	31,615	473
U.S. Bureau of Reclamation	0	0	9,354	129
U.S. Bureau of Indian Affairs	457	1,792	198,477	2,980
U.S. Navy	651	2,499	348,327	5,186
Total Federal Agencies (6)	2,134	$8,200	1,125,533	$16,800

Customer	Capacity Sales		Energy Sales	
Privately Owned Utilities	MW	Revenue	MWH	Revenue
California Pacific National Corp.	0	$ 0	0	$ 0
Colockum Transmission Co.	464	212	78,081	985
Idaho Power Co.	0	0	313,656	4,583
Montana Power Co.	960	3,634	1,013,335	14,165
Pacific Power & Light Co.	12,966	45,394	1,634,217	24,399
Portland General Elec. Co.	8,831	28,959	1,161,849	17,828
Puget Sound P&L Co.	2,939	4,550	1,224,921	20,130
Utah Power & Light Co.	0	0	307,590	4,747
Washington Water Power	1,333	3,805	915,358	13,059
Total Privately Owned Utilities (9)	27,493	$86,554	6,649,007	$99,896

Customer	Capacity Sales		Energy Sales	
Aluminum Industries	MW	Revenue	MWH	Revenue
Alcoa	5,253	$ 43,690	3,738,675	$ 34,769
Arco Aluminum Co.	3,997	32,737	2,888,168	27,021
Commonwealth Aluminum Co.	1,726	14,309	1,176,407	11,192
Intalco Aluminum Co.	5,314	43,583	3,841,066	35,590
Kaiser Aluminum	5,925	44,772	3,551,776	32,883
Martin Marietta Co.	1,888	18,801	1,006,145	8,721
Reynolds Metals Co.	6,720	55,902	4,771,623	43,618
Total Aluminum Industries (7)	30,823	$253,794	20,973,860	$193,794

Customer	Capacity Sales		Energy Sales	
Other Industries	MW	Revenue	MWH	Revenue
Carborundum Co.	2	$ 22	1,114	0
Georgia Pacific Corp.	373	3,004	261,806	2,452
Gilmore Steel	3	26	1,273	16
Hanna Nickel Smelting	0	0	448,293	3,147
Oregon Metallurgical	85	693	54,774	504
Pacific Carbide	112	880	72,453	663
Pennwalt Corporation	695	5,667	490,435	4,484
Pt Townsend Paper	177	1,469	102,353	929
Stauffer Chemical	0	0	0	114
Stewart Elsner/Camp High Cliff	0	0	0	0
Total Other Industries (10)	1,447	11,761	1,432,501	12,309
Total Sales NW Region (152)	132,602	$627,569	68,102,995	$879,735

Customer	Capacity Sales		Energy Sales	
Outside Northwest Region	MW	Revenue	MWH	Revenue
B.C. Hydro - Public	0	$ 0	95,500	$ 476
Bountiful, UT - Public	0	0	3,065	57
Burbank, CA - Public	0	0	303,078	6,686
Cominco, LTD., B.C. - Private	300	336	(11,037)	(309)
Glendale, CA - Public	0	0	246,461	5,135
Los Angeles, CA - Public	0	0	3,136,662	74,538
No. California Power Agency	0	0	34,117	686
Pasadena, CA - Public	0	0	194,685	4,247
Santa Clara, CA - Public	0	0	71,029	1,965
Pacific Gas & Elec. Co. Private	3,000	7,673	5,792,172	131,613
San Diego Gas & Elec. - Private	0	0	364,625	7,902
Sierra Pacific Power Co. - Private	0	0	5,400	100
So. Cal. Edison Co. - Private	0	0	5,736,256	129,253
State of California - Public	0	0	319,645	6,052
WAPA-Mid Pacific Region-Federal	1,200	5,235	1,054,238	24,819
Total Outside NW Region (15)	4,500	13,244	17,345,896	393,220
Total Sales Excluding Residential Exchange (167)	137,102	$640,813	85,448,891	$1,272,955

Customer	Capacity Sales		Energy Sales	
Residential Exchange	MW	Revenue	MWH	Revenue
Benton REA	446	$ 2,886	204,959	$ 1,573
Blachly-Lane Coop.	93	568	39,800	352
CP National	515	3,817	257,403	1,991
Central Elec. Coop.	469	2,814	208,077	1,692
Clark County PUD	3,010	21,773	1,436,760	12,667
Clearwater Power Co.	225	1,250	89,771	849
Consumers Power Co.	438	2,652	190,693	1,638
Coos-Curry Coop.	281	1,655	119,901	1,055
Douglas Elec. Coop.	201	1,248	89,496	760
Fall River Elec. Coop.	183	1,050	78,836	572
Idaho Power Co.	8,647	68,057	4,665,048	32,015
Lewis County PUD	106	698	48,536	267
Lincoln Elec. Coop. - Wash.	198	1,208	94,153	573
Lost River Elec. Coop.	101	654	47,242	323
Lower Valley Power & Light	358	2,087	148,407	1,311
Montana Light & Power	23	146	9,596	93
Montana Power	905	7,894	527,917	3,646
Pacific Power & Light	12,068	97,513	6,516,510	47,628
Portland General Electric	11,327	88,436	5,871,263	45,929
Puget Sound Power & Light	15,732	119,922	7,954,921	64,645
Raft River Coop.	241	1,571	126,855	609
Snohomish PUD	5,322	36,657	2,446,758	22,254
Umatilla Elec. Coop.	543	3,762	273,906	1,686
Utah Power Co.	1,759	12,817	948,384	5,655
Washington Water Power	5,847	45,829	3,056,683	24,262
Total Residential Exchange (24)	69,038	$ 526,964	35,451,875	$ 274,045
Total Sales	206,140	$1,167,777	120,900,766	$1,547,000

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

We have examined the balance sheets of the Federal Columbia River Power System (FCRPS) as of September 30, 1985 and 1984, and the related statements of revenues and expenses, changes in capitalization and source and use of funds for the years then ended. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As discussed in Note 2, FCRPS prepared its financial statements prior to fiscal year 1985 in accordance with the accounting practices prescribed by applicable legislation and executive directives of government agencies. These practices differed in some respects from generally accepted accounting principles. Accordingly, our auditors' report dated December 14, 1984, was qualified as the financial statements were not presented in accordance with generally accepted accounting principles. For fiscal year 1985 the financial statements have been prepared in accordance with generally accepted accounting principles and fiscal year 1984 financial statements have been retroactively restated. As a result of the restatement, our present opinion on the 1984 financial statements has been revised.

As discussed in Note 8, pending and threatened litigation surrounding the Washington Public Power Supply System (the Supply System), including litigation relating to the Supply System's nuclear projects Nos. 4 and 5 for which FCRPS has no obligation, may have a significant impact on FCRPS. The ultimate impact on FCRPS, if any, presently cannot be determined.

In our opinion, subject to the effect of any adjustments that might have been required had the outcome of the litigation mentioned in the preceding paragraph been known, the financial statements referred to above present fairly the financial position of FCRPS as of September 30, 1985 and 1984, and its revenues and expenses, changes in capitalization and source and use of funds for the years then ended, in conformity with generally accepted accounting principles applied on a consistent basis after giving retroactive effect to the changes in accounting methods, with which we concur, as more fully discussed in Note 2.

Our examinations were made 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, 1985 (Schedule A) is presented for purposes of additional analysis and is not a required part of the basic financial statements. The information in Schedule A has been subjected to the auditing procedures applied in the examination 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.

Portland, Oregon,
December 16, 1985.

Arthur Andersen & Co.

Federal Columbia River Power System
Statements of Revenues and Expenses
For the Years Ended September 30, 1985 and 1984

	1985	1984
	(Thousands of Dollars)	
Operating Revenues (Notes 1 and 6):		
Sales of electric power-		
Publicly owned utilities	$1,048,227	$ 901,568
Privately owned utilities	1,133,583	917,184
Federal agencies	61,467	77,032
Aluminum industry	447,589	622,526
Other industry	23,911	27,045
	2,714,777	2,545,355
Other operating revenues-		
Wheeling	149,166	104,847
Other	17,916	16,273
	167,082	121,120
Total operating revenues	2,881,859	2,666,475
Operating Expenses:		
Operation	193,295	169,713
Maintenance	83,095	79,634
Purchase and exchange power (Notes 1, 5 and 8)-		
Hanford	51,079	26,826
Trojan	51,816	39,452
WNP No. 1	206,272	228,862
WNP No. 2	357,843	393,169
WNP No. 3	206,239	175,818
Other	16,166	8,187
Residential energy purchased (Note 6)	1,007,449	835,254
Conservation costs (Note 1)	21,934	14,118
Depreciation (Notes 1 and 2)	128,999	114,390
Total operating expenses	2,324,187	2,085,423
Net operating revenues	557,672	581,052
Interest Expense (Notes 1, 3 and 4):		
Interest on federal investment-		
On appropriated funds	208,779	227,699
On Transmission System Act borrowings	164,269	129,859
Allowance for funds used during construction	(38,824)	(27,833)
Net interest expense	334,224	329,725
Net Revenues	$ 223,448	$ 251,327

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System
Balance Sheets
September 30, 1985 and 1984

Assets	1985	1984
	(Thousands of Dollars)	
Utility Plant (Notes 1, 2 and 4):		
Completed plant	$ 7,782,095	$ 7,460,303
Accumulated depreciation	(1,535,148)	(1,416,770)
	6,246,947	6,043,533
Construction work in progress	616,031	634,457
Net utility plant	6,862,978	6,677,990
Capitalized Contracts (Notes 2 and 5):		
Purchased power-		
Hanford	30,840	37,205
Trojan	134,960	137,715
WNP No. 1	2,124,415	2,134,200
WNP No. 2	2,281,995	2,298,920
WNP No. 3	1,590,360	1,596,535
Other	39,070	39,405
Conservation	17,000	—
Total capitalized contracts	6,218,640	6,243,980
Deferred Conservation Investment, net of accumulated amortization ($37,804 in 1985 and $20,218 in 1984) (Notes 1 and 3)	397,495	312,014
Current Assets:		
Unexpended funds	153,793	182,593
Accounts receivable	12,603	26,558
Accrued unbilled revenues	89,690	109,710
Materials and supplies, at average cost	33,640	37,449
Total current assets	289,726	356,310
Other Assets:		
Trust funds	7,177	7,686
Investment in Teton and Libby dams (Note 7)	30,591	32,449
Other	59,249	36,382
Total other assets	97,017	76,517
	$13,865,856	$13,666,811

Capitalization and Liabilities	1985	1984
	(Thousands of Dollars)	
Accumulated Net Revenues (Expenses) (Notes 2 and 4)	$ (308,557)	$ (532,005)
Federal Appropriations (Note 4)	6,439,843	6,364,004
Long-Term Debt (Notes 3 and 4)	1,340,000	1,405,000
Capitalized Contract Obligations (Notes 2 and 5)	6,166,075	6,201,640
Commitments and Contingencies (Notes 7 and 8)		
Current Liabilities:		
Current portion of capitalized contract obligations (Notes 2 and 5)	52,565	42;340
Accounts payable	148,686	149,983
Employees' accrued leave	10,938	10,655
Total current liabilities	212,189	202,978
Deferred Credits:		
Trust fund advances	7,177	7,686
Other	9,129	17,508
Total deferred credits	16,306	25,194
	$13,865,856	$13,666,811

The accompanying notes are an integral part of these balance sheets.

Federal Columbia River Power System
Statements of Changes in Capitalization
For the Years Ended September 30, 1985 and 1984

	Accumulated Net Revenues (Expenses)	Federal Appropriations	Long-Term Debt	Capitalized Contract Obligations	Total Capitalization
	(Thousands of Dollars)				
Balance At September 30, 1983, as previously reported	$ 61,330	$6,446,482	$1,165,000	$ —	$ 7,672,812
Cumulative effect on prior years of changes in accounting methods (Note 2)-					
Depreciation	(654,924)	—	—	—	(654,924)
Net billing advances	(189,738)	—	—	—	(189,738)
Capitalized contract obligations	—	—	—	6,273,905	6,273,905
Balance At September 30, 1983, as restated	(783,332)	6,446,482	1,165,000	6,273,905	13,102,055
Congressional appropriations	—	209,033	—	—	209,033
Net increase (decrease) in long-term debt and capitalized contract obligations	—	—	240,000	(29,925)	210,075
Funds returned to U.S. Treasury	—	(291,511)	—	—	(291,511)
Net revenues	251,327	—	—	—	251,327
Balance At September 30, 1984	(532,005)	6,364,004	1,405,000	6,243,980	13,480,979
Congressional appropriations	—	157,505	—	—	157,505
Net increase (decrease) in long-term debt and capitalized contract obligations	—	—	(65,000)	(25,340)	(90,340)
Funds returned to U.S. Treasury	—	(81,666)	—	—	(81,666)
Net revenues	223,448	—	—	—	223,448
Balance At September 30, 1985	$(308,557)	$6,439,843	$1,340,000	$6,218,640	$13,689,926

The accompanying notes are an integral part of these statements.

Federal Columbia River Power System
Statements of Source and Use of Funds
For the Years Ended September 30, 1985 and 1984

	1985	1984
	(Thousands of Dollars)	
Source of Funds:		
Operations-		
Net revenues	$223,448	$251,327
Charges not requiring funds:		
Depreciation	128,999	114,390
Amortization of conservation investment	17,586	13,636
Funds provided from operations	370,033	379,353
Congressional appropriations	157,505	209,033
Increase in long-term debt	150,000	240,000
Issuance of capitalized contract obligations	17,000	—
Reduction of capitalized contracts	42,340	29,925
Decrease (increase) in current assets-		
Unexpended funds	28,800	(38,544)
Receivables	33,975	(29,345)
Materials and supplies	3,809	3,958
Increase (decrease) in current liabilities-		
Accounts payable	(1,297)	(49,012)
Employees' accrued leave	283	547
Other sources (uses), net	(29,388)	(4,110)
Total funds provided	$773,060	$741,805
Use Of Funds:		
Investment in utility plant, net	$313,987	$353,586
Investment in capitalized contracts	17,000	—
Investment in conservation	103,067	66,783
Funds returned to U.S. Treasury	81,666	291,511
Reduction of long-term debt	215,000	—
Payment of capitalized contract obligations	42,340	29,925
Total funds used	$773,060	$741,805

The accompanying notes are an integral part of these statements.

1. Summary of Accounting Policies:

General

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 Corps of Engineers (Corps) and the Bureau of Reclamation (Bureau) 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 under the FCRPS title. Costs of multipurpose Corps and Bureau projects are assigned to specific purposes through a cost allocation process. The portion of total project costs allocated to power is included in these statements as utility plant.

FCRPS accounts are kept in accordance with 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 government departments (BPA is a unit of the Department of Energy; the Bureau is part of the Department of Interior and the Corps is part of the Department of Defense). Properties and income are tax-exempt.

Regulatory Authority

FCRPS power rates must be confirmed and approved by FERC.

Revenues

Operating revenues are recorded on the basis of service rendered.

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 cost of additions, major replacements and betterments is capitalized. Repairs and minor replacements are charged to operating expense. The cost of utility plant retired, together with removal costs and 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) is 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 noncash reduction of interest expense.

AFUDC capitalization rates are stipulated for certain generating projects (2.5% to 12.375%) and approximate the cost of borrowings from the U.S. Treasury for other construction (12.8% in 1985 and 10.6% in 1984).

Depreciation

Depreciation of utility plant is computed on the straight-line method based on estimated service lives of the various classes of property, which average 45 years for transmission and 85 years for generation. Since power rates are set attempting to recover the cost of transmission facilities within their average service lives and within 50 years for generating facilities, the annual depreciation charges are not matched directly with the related revenue recovery period and will, in the case of generating facilities, continue beyond the period in which such costs will have been recovered through revenues. Also see Note 2.

Capitalized Contracts and Capitalized Contract Obligations

BPA has agreed to purchase all or part of the generating capability of several nuclear power plants and one hydro project. BPA has also agreed to fund debt service on Eugene Water and Electric Board (EWEB) bonds issued to finance conservation programs sponsored by BPA. The capitalized contracts will be amortized as such costs are scheduled to be recovered in rates.

Deferred Conservation Investment

Energy conservation costs are capitalized and amortized over twenty years, which is the planned revenue recovery period. Conservation amortization was $17,586,000 for 1985 and $13,636,000 for 1984.

Retirement Benefits

FCRPS employees belong to the federal government's Civil Service Retirement Fund, a contributory pension plan. Retirement benefits are payable by the U.S. Treasury and not by the FCRPS.

Reclassifications

Certain reclassifications of prior year amounts have been made to conform to 1985 financial statement presentation.

2. Changes in Accounting and Reporting:

Depreciation

In 1985, FCRPS changed its method of computing depreciation from the compound interest method to the straight-line method to be in accordance with generally accepted accounting principles. The 1984 financial statements have been retroactively restated for this change, which reduced previously reported net revenues by $39,441,000 and the beginning balance of accumulated net revenues for that year by $654,924,000.

Thermal Plant Net Billing Advances

Net billing agreements provide that BPA make payments and/or grant billing credits before a nuclear project's date of commercial operation. At September 30, 1983, payments and billing credits totaling $189.7 million made prior to December 20, 1979 for Washington Public Power Supply System Nuclear Project No. 2 (WNP No. 2) were included as "net billing advances" in the FCRPS balance sheet. Because recovery of such amount was not provided for in rates, net billing advances were expensed in 1984. Similar payments and billing credits made since December 20, 1979 have been charged to purchase and exchange power expense, which matches their recovery in rates.

Had net billing advances been consistently expensed in accordance with generally accepted accounting principles prior to 1984, the $189.7 million writeoff in 1984 would not have been necessary. Therefore, to present the 1984 statement of revenues and expenses in accordance with generally accepted accounting principles, the writeoff has been reflected as an adjustment to beginning accumulated net revenues for that year. The result of the adjustment increases previously reported net revenues for 1984 by $189.7 million.

Capitalized Contract Obligations

Prior to fiscal 1985, BPA's obligation to purchase all or part of the generating capability of several projects and also fund debt service incurred on bonds issued for BPA sponsored conservation programs was treated as a purchase commitment but not recorded as an asset and liability on the balance sheet. Since generally accepted accounting principles require that such commitments be recorded no later than fiscal 1988 and encourage earlier application, the obligations were recorded in fiscal 1985 and 1984 financial statements were retroactively restated. The effect is an increase in assets and liabilities by $6,218,640,000 for fiscal year 1985 and $6,243,980,000 for fiscal year 1984. However, since the commitments were already being charged to expense as they came due, there is no effect on the statement of revenues and expenses or accumulated net revenues. Also see Note 5.

3. Long-Term Debt:

In order to finance its 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 bonds issued by government corporations. $1.25 billion of the $3.75 billion is reserved for conservation and renewable resource loans and grants. $340 million of this reserved amount and $1 billion of other borrowings were outstanding at September 30, 1985 as shown below:

Construction Debt			Conservation Debt		
Maturity Date	Interest Rate	Amount	Maturity Date	Interest Rate	Amount
		(Thousands)			*(Thousands)*
2013	8.95%	$ 50,000	1990	10.15%	$ 50,000
2014	9.45%	35,000	2003	12.20%	140,000
2016	14.40%	50,000	2004	13.05%	150,000
2016	16.60%	175,000	Total		$340,000
2017	10.85%	40,000			
2017	14.15%	85,000			
2017	14.40%	100,000			
2018	11.70%	30,000			
2018	12.25%	45,000			
2018	12.30%	30,000			
2019	13.05%	60,000			
2030	11.25%	100,000			
Total Bonds		800,000			
Note Payable					
1986	(1) 8.20%	200,000			
Total		$1,000,000			

(1) Included as long-term debt because BPA intends to renew the note.

The weighted average bond interest rate was 12.3% in 1985 and 12.8% in 1984. Most of the construction bonds have a provision that they may not be paid back until at least five years after the date of issuance.

4. Federal Appropriations:

Construction and replacement of Corps and Bureau generating facilities are financed by annual Congressional appropriations. Annual appropriations are also made for operation and maintenance costs, although these are repaid to the U.S. Treasury by the end of each fiscal year. BPA was also financed through appropriations before the Federal Columbia River Transmission Act was passed in 1974.

Interest rates on the appropriated funds range from 2.5% to 12.375% (the weighted average rate was 3.2% in 1985 and 3.4% in 1984). The rates have been set either by law, administrative order pursuant to law, or administrative policies.

Federal appropriations and long-term debt in generating projects and the transmission system are to be repaid to the U.S. Treasury within 50 and 45 years, respectively, from the time each facility is placed in service. The cumulative amount of federal appropriations and long-term debt repaid through September 30, 1985 exceeded the amount required to be repaid.

The following table shows the planned and required repayment of the remaining federal appropriations and long-term debt as of September 30, 1985.

	Planned to be Repaid	Required to be Repaid
	(Thousands of Dollars)	
1986	$ 190,825	$ 19,367
1987	148,645	9,498
1988	164,063	32,477
1989	174,947	832
1990	183,822	4,672
1991-1995	1,005,214	166,046
1996-2000	924,621	246,744
2001-2005	1,150,222	1,108,948
2006-2010	1,336,228	835,559
2011-2015	1,161,418	967,818
2016-2020	1,339,838	1,766,802
2021-2025	—	1,316,563
After 2025	—	1,304,517
	$7,779,843	$7,779,843

If, in any given year, there are not enough revenues to cover all cash needs, including interest, any deficiency becomes unpaid annual expense. This must be paid from subsequent years' revenues before any repayment of federal appropriations and long-term debt can be made. As of September 30, 1983, there was $217.6 million of unpaid annual expense through fiscal year 1983. This unpaid annual expense was collected in revenues and repaid during fiscal year 1984.

5. Purchase and Exchange Power:

BPA has acquired all or part of the generating capability of several nuclear power plants from a group of utilities under net billing agreements. The agreements require BPA to pay all or part of the annual project budgets, including debt service, whether or not the projects are completed. BPA has also acquired all of the output of a hydro project and has agreed to fund debt service on EWEB bonds issued to finance conservation programs sponsored by BPA. Total debt service for the capitalized contracts was $585.6 million and $582.0 million in 1985 and 1984, respectively, of which $547.1 million and $543.4 million represented interest. The projected payments under these agreements are shown below:

Project and % Capability Acquired	Project Status	Capacity in Megawatts	Estimated BPA Portion	Estimated Annual Project Costs 1986	1987	1988	1989	1990
				(Thousands of Dollars)				
Hanford Generating Project (50%)	Operational	430	Interest	$ 900	$ 800	$ 680	$ 570	$ 410
			Principal	3,200	3,400	3,480	3,590	5,110
			Operations	56,600	57,300	58,900	61,600	65,500
Trojan Nuclear Project (30%)	Operational	339	Interest	7,700	7,500	7,400	7,200	7,100
			Principal	2,900	3,000	3,200	3,300	3,500
			Operations	39,600	42,400	44,700	47,400	50,100
WNP No. 1 (100%)	Preservation	1,250	Interest	188,000	186,400	190,360	189,050	186,340
			Principal	15,000	16,100	18,280	19,590	21,740
			Preservation (a)	—	—	—	—	—
WNP No. 2 (100%)	Operational	1,100	Interest	196,200	193,900	194,190	192,180	190,080
			Principal	23,700	25,800	27,110	29,020	31,120
			Operations	166,700	142,700	171,400	180,500	191,600
WNP No. 3 (70%)	Preservation	868	Interest	145,100	154,200	152,450	151,580	150,730
			Principal	7,100	9,300	10,750	11,520	12,370
			Preservation (a)	42,000	36,400	39,400	35,300	35,600
Idaho Falls Hydro	Operational	24	Interest	3,092	3,695	3,667	3,636	3,599
			Principal	10	410	440	470	500
			Operations	1,108	1,160	1,220	1,280	1,345
EWEB Conservation	N/A	N/A	Interest	1,393	1,357	1,315	1,268	1,213
			Principal	655	690	730	780	830
				$900,958	$886,512	$929,672	$939,834	$958,787

(a) Estimated preservation costs during the delay period for WNP No. 1 are not shown separately because it is anticipated such costs will be funded by WNP No. 1 bond funds currently available. Estimated preservation costs for WNP No. 3 include the 30% IOU share assumed by BPA pursuant to the settlement agreements. See Note 8.

BPA's commitment under the net billing agreements extends for the life of the projects. One of the projects, WNP No. 2, started operation in 1984. Construction of two other projects, WNP No. 1 and WNP No. 3, has been delayed. A construction restart of WNP No. 1 and WNP No. 3 and the need for more financing will depend on factors such as the forecasted power needs in the Pacific Northwest and the cost effectiveness of these projects compared to other resources.

6. Residential Energy Exchange:

As provided for in the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act), Section 5(c), BPA entered into contracts with several electric utilities. These contracts allow each utility to sell BPA a portion of its residential load (the portion increased from 90% to 100% on July 1, 1985) at the average system cost of the utility's resources in each year. In exchange, BPA sells the utilities electric power for their residential loads at BPA's priority firm power rates. Purchases and sales of electric power by BPA during fiscal years 1985 and 1984 under these contracts were as follows:

	1985	1984
	(Thousands of Dollars)	
Residential energy purchased (included in operating expenses)	$1,007,449	$835,254
Residential energy sold (included in operating revenues)	801,010	650,958
Net residential exchange costs	$ 206,439	$184,296

The Regional Act provides that the net residential exchange costs projected in each rate period before July 1, 1985 that are not allocated to other customers be included in the direct service industrial rates. Thus, operating revenues from the direct service industries also include amounts for net residential exchange costs to the extent they have been projected.

7. Commitments and Contingencies:

Irrigation Assistance

Legislation requires that FCRPS net revenues will be used to pay the U.S. Treasury for costs allocated to irrigation of certain Pacific Northwest projects that are determined by the Secretary, Department of Interior, to be beyond the ability of the irrigation water users to repay. The first planned irrigation assistance payment from power revenues will be made in 1997, and payments will ultimately total $769 million. Although paid by power ratepayers, such costs are for the benefit of the water users and are not a regular operating cost of the power program. Accordingly, they are not included in the body of the financial statements.

Investment in Teton Dam and Libby Reregulating Dam

On June 5, 1976, Teton Dam was extensively damaged before it had been completed. The total investment in the project at September 30, 1985 (excluding interest totaling $2.2 million after June 1976, which has been charged to expense) was $79.1 million. The portion allocated to power was $11.0 million, and the portion allocated to irrigation but repayable from power revenues was $52.8 million.

On September 8, 1978, the Corps was stopped from constructing a reregulating dam at Libby, Montana because it lacked specific Congressional authority. Later appeals by the Corps to remove the injunction were denied. Investment in the reregulating dam was $19.6 million at September 30, 1985.

The final decision about repayment obligations for the projects depends on Congressional action. If repayment is not required, the investment will be paid by the U.S. Government. Should FCRPS be directed to pay, the costs will be recovered through rates. Until a decision is made, the investment allocated to power is included as a deferred charge in the balance sheet and costs of irrigation assistance are included in the total of irrigation assistance described above.

Residential Energy Exchange

Section 7(b)(3) of the Regional Act provides that if there is an overall net revenue surplus or deficiency for the period ending June 30, 1985, a portion of it be recovered from or repaid to customers, over a reasonable period of time, on the basis of power sales during that period. The affected amount is the surplus or deficiency during the period caused by (1) a difference between projected and actual power deliveries to the direct service industrial customers and (2) recovering too little or too much of the net residential exchange costs.

The method of determining the overall surplus or deficiency for the period has not been completed or agreed to by those involved. In the opinion of BPA management, the amount will not have a material effect on the FCRPS financial statements.

Nuclear Insurance

BPA is a member of Nuclear Electric Insurance Limited (NEIL) which was established to provide insurance coverage for replacement power costs resulting from an accidental outage at a member's nuclear site and for excess property damage and decontamination liability. Under these coverages, BPA could be subject to a maximum assessment of $9,453,000 in the event of a loss to any NEIL-insured nuclear plant, including WNP No. 2. In addition, the Nuclear Regulatory Commission's indemnity for public liability coverage under the Price-Anderson Act is supported by a mandatory industry-wide program. Under the program, owners of nuclear generating facilities could be assessed in the event of nuclear incidents. BPA could be subject to a retrospective assessment of $5,000,000 in the event of an incident, limited to a maximum of $10,000,000 in any calendar year.

8. Litigation:

Litigation Involving Rates

BPA is involved in litigation concerning various rate matters. This litigation includes: (a) various challenges to BPA's determination of the average system cost of certain utilities participating in the residential energy exchange (see Notes 6 and 7); (b) various challenges to the 1983 regional wholesale and transmission rates (confirmed and approved by the FERC on July 2, 1985); and (c) other rate and Regional Act matters.

In the opinion of BPA General Counsel, either the likelihood of success by the filing party is remote; the ultimate outcome will not have a material effect on the FCRPS financial statements; or any payments by BPA resulting from the litigation would be recovered through future rates.

Litigation Involving the Washington Public Power Supply System (the Supply System)

On January 22, 1982, the Supply System stopped construction of two nuclear projects: WNP No. 4 at Hanford and WNP No. 5 at Satsop. After the termination, the Supply System defaulted on $2.25 billion of outstanding WNP Nos. 4 and 5 bonds for which FCRPS has no obligation, and delayed construction of WNP Nos. 1 and 3. The above actions of the Supply System have led to a number of lawsuits which involve BPA. In the opinion of BPA General Counsel, BPA has valid defenses to the direct claims against BPA and the possibility of the plaintiffs prevailing against BPA is remote.

WNP Nos. 1 and 4 and WNP Nos. 3 and 5 share certain common facilities. The participants of the terminated projects have demanded that the heretofore equitably shared costs be reallocated retroactively to WNP Nos. 1 and 3. If the plaintiffs are successful, this could result in these two projects assuming additional costs of $192 to $400 million. Because of the net billing agreements discussed in Note 5, which require BPA to pay the participants' portion of the annual project costs for WNP Nos. 1, 2 and 3, BPA might be required to fund judgements against the Supply System affecting the net-billed projects.

The construction delay of WNP No. 3 precipitated litigation by the Investor Owned Utilities (IOUs) who own a 30% share of the project. BPA and the IOUs have negotiated settlement agreements. The guiding principle of the agreements is to put the IOUs in a position similar to what they could have expected had WNP No. 3 not been mothballed. Thus, BPA is obligated to deliver an amount of power (expected to be 191 annual average MW) to the IOUs over the expected life of a nuclear power plant (30-32 years) at a formula price. In exchange for the power, the IOUs will make combustion turbines available for BPA's use and give BPA an irrevocable offer of their share of the project capability. In addition, BPA has agreed to assume all future costs associated with the preservation or completion of WNP No. 3. The settlement agreements have themselves generated a new round of litigation. In the opinion of BPA General Counsel, the likelihood that the challenges to the settlement agreements will prevent them from going into effect or that any such challenges will have any financial impact on BPA is remote.

In addition to direct claims against BPA, there are lawsuits against the Supply System brought by the bondholders and the bond fund trustee, utilities who loaned money to the Supply System to pay for mothballing and termination of WNP Nos. 4 and 5, and lawsuits brought by contractors regarding claims for goods and services provided for WNP Nos. 4 and 5. Many of these litigants have asserted a right to execute on all the assets of the Supply System including WNP Nos. 1, 2 and 3 to satisfy judgments in their favor. The claims of the bondholders and the bond fund trustee are still in the discovery stage with trial expected in 1987. The Washington Supreme Court has ruled that the utilities who loaned money to the Supply System to pay for the mothballing and termination of WNP Nos. 4 and 5 were limited to satisfying their judgment from the funds of WNP Nos. 4 and 5. There are five claims by contractors of WNP Nos. 4 and 5 currently being litigated. Four of the cases have yet to be tried. The Supply System has appealed the judgment in favor of the contractor in the fifth case. BPA will vigorously oppose any attempt of these litigants to satisfy their claims from the assets of WNP Nos. 1, 2 and 3, but BPA General Counsel cannot predict the outcome of these claims until they are made.

Other Matters

Certain other claims, suits and complaints have been filed or are pending against entities of FCRPS. In the opinion of counsel and management for those entities, these actions are either without merit or involve amounts which are not material to the FCRPS financial statements.

Federal Columbia River Power System
Schedule of Amount and Allocation of Plant Investment
September 30, 1985

Project	Total	Commercial Power: Completed Plant	Commercial Power: Construction Work in Progress	Commercial Power: Total Commercial Power	Irrigation: Returnable From Commercial Power Revenues	Irrigation: Returnable From Other Sources	Irrigation: Total Irrigation	Nonreimbursable: Navigation	Nonreimbursable: Flood Control	Nonreimbursable: Fish and Wildlife	Nonreimbursable: Recreation	Nonreimbursable: Other (b)	Schedule A: Percent of total Returnable From Commercial Power Revenues
					(Thousands of Dollars)								
Projects in Service:													
Transmission facilities (BPA)	$ 3,068,208	$2,653,306	$414,902	$3,068,208	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	100.0%
Bureau projects-													
Boise	79,723	7,243	2,705	9,948	17,240	35,543	52,783	—	16,992	—	—	—	34.1%
Columbia Basin	1,663,834	941,504	40,942	982,446	541,075	83,206	624,281	1,000	51,835	3,591	155	526	91.6%
Hungry Horse	101,835	77,062	80	77,142	—	—	—	—	24,693	—	—	—	75.8%
Minidoka-Palisades	207,906	14,153	60	14,213	10,301	115,701	126,002	—	60,892	1,209	5,590	—	11.8%
Yakima	137,307	5,179	14	5,193	11,208	116,578	127,786	—	959	3,131	238	—	11.9%
Total Bureau projects	2,190,605	1,045,141	43,801	1,088,942	579,824	351,028	930,852	1,000	155,371	7,931	5,983	526	76.2%
Corps projects-													
Albeni Falls	33,965	32,236	89	32,325	—	—	—	136	175	—	1,329	—	95.2%
Bonneville	808,644	711,612	48,487	760,099	—	—	—	45,193	—	—	1,290	2,062	94.0%
Chief Joseph	518,821	510,612	392	511,004	752	—	752	—	—	—	2,118	4,947	98.6%
Cougar	60,842	18,445	272	18,717	—	3,074	3,074	547	38,296	—	—	208	30.8%
Detroit-Big Cliff	67,558	40,698	343	41,041	—	5,122	5,122	237	21,158	—	—	—	60.7%
Dworshak	359,262	301,546	907	302,453	—	—	—	9,517	34,382	—	12,910	—	84.2%
Green Peter-Foster	90,699	50,075	23	50,098	—	5,856	5,856	367	30,467	—	1,856	2,055	55.2%
Hills Creek	49,067	17,537	—	17,537	—	4,322	4,322	626	26,310	—	—	272	35.7%
Ice Harbor	211,554	152,897	9,610	162,507	—	—	—	46,205	—	—	2,842	—	76.8%
John Day	563,526	411,664	5,886	417,550	—	—	—	87,476	20,612	—	11,479	26,409	74.1%
Libby	603,316	411,840	54,252	466,092	—	—	—	—	97,949	3,044	5,594	30,637	77.3%
Little Goose	269,191	218,473	9,580	228,053	—	—	—	34,483	—	—	4,051	2,604	84.7%
Lookout Point-Dexter	98,626	46,883	126	47,009	—	1,387	1,387	741	48,874	—	521	94	47.7%
Lost Creek	150,062	26,981	8	26,989	—	2,015	2,015	—	53,325	24,468	29,409	13,856	18.0%
Lower Granite	425,017	342,567	9,598	352,165	—	—	—	52,369	—	—	12,641	7,842	82.9%
Lower Monumental	287,113	235,095	9,630	244,725	—	—	—	39,149	—	—	2,822	417	85.2%
McNary	350,693	273,968	5,614	279,582	—	—	—	68,115	—	—	2,996	—	79.7%
The Dalles	329,449	280,519	2,511	283,030	—	—	—	44,315	—	—	2,082	22	85.9%
Total Corps projects	5,277,405	4,083,648	157,328	4,240,976	752	21,776	22,528	429,476	371,548	27,512	93,940	91,425	80.4%
Irrigation assistance at 12 projects having no power generation	173,258	—	—	—	125,543	47,715	173,258	—	—	—	—	—	72.5%
Total plant investment	10,709,476	7,782,095	616,031	8,398,126	706,119	420,519	1,126,638	430,476	526,919	35,443	99,923	91,951	85.0%
Repayment obligation retained by Columbia Basin Project	4,639	2,836 (a)	—	2,836	1,803	—	1,803	—	—	—	—	—	100.0%
Other repayment obligation	9,281	—	30	30	9,251	—	9,251	—	—	—	—	—	100.0%
Investment in Teton and Libby Projects (c)	98,675	—	30,591	30,591	52,828	3,672	56,500	—	9,151	—	2,433	—	84.5%
Total	$10,822,071	$7,784,931	$646,652	$8,431,583	$770,001	$424,191	$1,194,192	$430,476	$536,070	$35,443	$102,356	$91,951	85.0%

(a) Joint facilities transferred to Bureau of Sport Fisheries and Wildlife. This portion is included in other assets and deferred charges in the accompanying balance sheets.
(b) Included in this amount are nonreimbursable road costs amounting to $77.1 million.
(c) The $11,023 commercial power portion of the Teton dam and the $19,568 portion of Libby related to the reregulating dam are included in other assets and deferred charges in the accompanying balance sheets. Teton amounts exclude interest totaling approximately $2.2 million subsequent to June 1976 which has been charged to expense.

Federal Colimbia River Power System General Specifications of Projects-Existing, Authorized or Licensed, and Potential Nameplate Rating of Installations September 30, 1985

				Existing		Authorized-Licensed		Potential		Project Totals	
Project	State	River	Initial Date In Service	Number of Units	Nameplate Rating-kw	Number of Units	Nameplate Rating-kw	Number of Units	Nameplate Rating-kw	Number of Units	Nameplate Rating-kw
Minidoka	Idaho	Snake	May 7, 1909	7	13,400	—	—	—	—	7	13,400
Boise River Div	Idaho	Boise	May 1912	3	1,500	—	—	—	—	3	1,500
Black Canyon	Idaho	Payette	Dec 1925	2	8,000	—	—	—	—	2	8,000
Grand Coulee	Washington	Columbia	Sep 28, 1941	24 -3	6,163,000	—	—	6	4,200,000	30 -3	10,363,000
Anderson Ranch	Idaho	S Fk Boise	Dec 15, 1950	2	40,000	—	—	1	13,500	3	53,500
Hungry Horse	Montana	S Fk Flathead	Oct 29, 1952	4	285,000	—	—	—	—	4	285,000
Chandler	Washington	Yakima	Feb 13, 1956	2	12,000	—	—	—	—	2	12,000
Palisades	Idaho	Snake	Feb 25, 1957	4	118,750	—	—	2	135,000	6	253,750
Roza	Washington	Yakima	Aug 31, 1958	1	11,250	—	—	—	—.	1	11,250
Grand Coulee PG	Washington	Columbia	Dec 30, 1974	6	300,000	—	—	—	—	6	300,000
Teton	Idaho	Teton			—	3	30,000	—	—	3	30,000
Total Bureau of Reclamation Number of Units and Nameplate Rating				55 -3	6,952,900	3	30,000	9	4,348,500	67 -3	11,331,400
Bonneville	Ore-Wash	Columbia	Jun 6, 1938	18 -2	1,076,600	—	—	—	—	18 -2	1,076,600
Detroit	Oregon	North Santiam	Jul 1, 1953	2	100,000	—	—	—	—	2	100,000
McNary	Ore-Wash	Columbia	Nov 6, 1953	14	980,000	6	747,000[1]	—	—	20	1,727,000
Big Cliff	Oregon	N Santiam	Jun 12, 1954	1	18,000	—	—	—	—	1	18,000
Lookout Point	Oregon	M Fk Willamette	Dec 16, 1954	3	120,000	—	—	—	—	3	120,000
Albeni Falls	Idaho	Pend Oreille	Mar 25, 1955	3	42,600	—	—	—	—	3	42,600
Dexter	Oregon	M Fk Willamette	May 9, 1955	1	15,000	—	—	—	—	1	15,000
Chief Joseph	Washington	Columbia	Aug 28, 1955	27	2,069,000	—	—	13	1,573,000	40	3,642,000
The Dalles	Ore-Wash	Columbia	May 13, 1957	22 -2	1,807,000	—	—	—	—	22 -2	1,807,000
Ice Harbor	Washington	Snake	Dec 18, 1961	6	602,880	—	—	—	—	6	602,880
Hills Creek	Oregon	M Fk Willamette	May 2, 1962	2	30,000	—	—	—	—	2	30,000
Cougar	Oregon	S Fk McKenzie	Feb 4, 1964	2	25,000	1	35,000	—	—	3	60,000
Green Peter	Oregon	Middle Santiam	Jun 9, 1967	2	80,000	—	—	—	—	2	80,000
John Day	Ore-Wash	Columbia	Jul 17, 1968	16	2,160,000	4	540,000	—	—	20	2,700,000
Foster	Oregon	S. Santiam	Aug 22, 1968	2	20,000	—	—	—	—	2	20,000
Lower Monumental	Washington	Snake	May 28, 1969	6	810,000	—	—	—	—	6	810,000
Little Goose	Washington	Snake	May 19, 1970	6	810,000	—	—	—	—	6	810,000
Dworshak	Idaho	N Fk Clearwater	Sep 18, 1974	3	400,000	3	660,000	—	—	6	1,060,000
Lower Granite	Washington	Snake	Apr 15, 1975	6	810,000	—	—	—	—	6	810,000
Libby	Montana	Kootenai	Aug 29, 1975	5	525,000	3	315,000[2]	—	—	8	840,000
Lost Creek	Oregon	Rogue	Dec 1, 1975	2	49,000	—	—	—	—	2	49,000
Libby Reregulating	Montana	Kootenai		—	—	3	76,400	—	—	3	76,400
Strube	Oregon	S Fk McKenzie		—	—	1	4,500	—	—	1	4,500
Total Corps of Engineers Number of Units and Nameplate Rating				149 -4	12,550,080	21	2,377,900	13	1,573,000	183 -4	16,500,980
Total Number of Units and Nameplate Rating				204 -7	19,502,980	24	2,407,900	22	5,921,500	250 -7	27,832,380

[1]McNary Second Powerhouse estimates includes 6 units of 124,500 KW each.
[2]Libby Units 6, 7, 8, at 105,000 KW each have been deferred.

Official Organization Chart
U.S. Department of Energy
Bonneville Power Administration

ADMINISTRATOR (A)
Peter T. Johnson

DEPUTY ADMINISTRATOR
Robert E. Ratcliffe

EXECUTIVE ASST. ADMINISTRATOR
James J. Jura

ASSISTANT ADMINISTRATOR
(Mgr. Wash., D.C. Office)
Larry C. Larson

ASSISTANT MANAGER
Robert E. Seifert

GENERAL COUNSEL (AP)
Harvard P. Spigal

DEPUTY GENERAL COUNSEL
Omar W. Halvorson

GENERATING PROJECTS (AG)
Douglas A. Hansen

EXTERNAL AFFAIRS (AL)
John S. Robertson

COUNCIL LIAISON (AR)
Myron B. Katz

SUPPLY SYSTEM PROGRAMS (AV)
James R. Lewis

CHIEF AUDITOR (AK)
Jack L. Strayer

ASST. TO THE ADMINISTRATOR
EQUAL OPPORTUNITY PROGRAMS (AH)
Curtis B. Kirkpatrick

ASST. ADM. FOR FINANCIAL MGT.
Financial Mgr. - Stephen A. Ailshie

DEPUTY FINANCIAL MANAGER
James H. Curtis

DIV. OF PLANNING & BUDGET
Director - Paul O. Crabtree, Jr.

DIV. OF FINANCIAL REQUIREMENTS
Director - Charles E. Meyer

DIV. OF FISCAL ACCOUNTING
& DISBURSEMENT
Director - Michael R. Federovitch

DIV. OF MANAGERIAL ACCOUNTING
Director - Patrica B. Johnson (Acting)

ASST. ADM. FOR ENGINEERING
& CONSTRUCTION
Chief Engineer - Marvin Klinger

DEPUTY CHIEF ENGINEER
Charles F. Clark

DEPUTY CHIEF ENGINEER
Charles F. Clark

ENGINEERING MANAGER
Michael L. Holm

DIV. OF MATERIALS & PROCUREMENT
Director - Steven C. Kallio
Asst. Dir. - Peter L. Semple (Acting)

DIV. OF SYSTEM ENGINEERING
Director - Dean E. Perry
Asst. Dir. - William A. Mittelstadt

DIV. OF RESOURCE ENGINEERING
Director - Walter E. Myers

DIV. OF LABORATORIES
Director - Alfred S. Capon
Asst. Dir. - Charles L. Nellis

DIV. OF PLANT SERVICES
Director - Ralph J. Wehrman
Asst. Dir. - James C. Johnson

DIV. OF CONSTRUCTION
Director - Clifford C. Perigo
Asst. Dir. - Edward A. Petersen

DIV. OF SUBSTATION & CONTROL ENGRG.
Director - Milton J. Brown
Asst. Dir. - Mark A. Reynolds

DIV. OF TRANSMISSION ENGINEERING
Director - Gary A. Parks
Asst. Dir. - Lyndon E. Bradshaw

DIV. OF LAND RESOURCES
Director - Wesley J. Kvarsten
Asst. Dir. - Milton F. Fyre (Acting)

ASST. ADM. FOR CONSERVATION
Conservation Mgr. - Steven G. Hickok

DEPUTY CONSERVATION MANAGER
Richard L. Perlas

DIV. OF PLANNING & EVALUATION
Director - W. Michael Warwick (Acting)

DIV. OF COMMERCIAL
& INDUSTRIAL PROGRAMS
Director - L. Kirk Hall

DIV. OF RESIDENTIAL PROGRAMS
Director - Sydney D. Berwager

ASST. ADM. FOR REGIONAL OPERATIONS
Regional Operations Mgr.
George A. Tupper

DEPUTY REGIONAL OPERATIONS MGR.
Bruce Rogers

DIV. OF SYSTEM OPERATIONS
Director - Duane K. Larson
Asst. Dir. - Darrel G. Vancoevering

DIV. OF MAINTENANCE
Director - Frederick M. Johnson

UPPER COLUMBIA AREA
Area Manager - Wayne Lee
Missoula Dist. Mgr. - George E. Eskridge
Wenatchee Mgr. - Ronald K. Rodewald

LOWER COLUMBIA AREA
Area Manager - George E. Gwinnutt
Eugene Dist. Mgr. - Ladd Sutton

PUGET SOUND AREA
Area Mgr. - George T. Reich (Acting)

SNAKE RIVER AREA
Area Mgr. - Thomas V. Wagenhoffer
Idaho Falls Dist. Mgr. - Robert N. Laffel
Boise Dist. Mgr. -
Frederick K. Rettenmund

ASST. ADM. FOR POWER
& RESOURCES MANAGEMENT
Power Mgr. - Edward W. Sienkiewicz, Jr.

DEPUTY POWER MANAGER
James L. Jones

ASST. POWER MGR. FOR NATURAL
RESOURCES & PUBLIC SERVICES
Janet W. McLennan

DIV. OF FISH & WILDLIFE
Director - John R. Palensky

DIV. OF CUSTOMER SERVICE
Director - Thomas M. Noguchi
Asst. Dir. - John B. Pyrch

DIV. OF RATES
Director - Shirley R. Melton
Asst. Dir. - John D. Carr

DIV. OF POWER SUPPLY
Director - Robert D. Griffin
Asst. Dir. - Douglas K. Faulkner

ASST. POWER MGR. FOR RESOURCES
PLANNING & ACQUISITION
Gary L. Fuqua

DIV. OF POWER FORECASTING
Director - Donald G. Hoffard
Asst. Dir. - Jack G. Hornor

DIV. OF POWER RESOURCES PLANNING
Director - Robert C. Lamb
Asst. Dir. - Terence G. Esvelt

ASST. ADM. FOR MANAGEMENT SERVICES
Administrative Mgr. - George E. Bell

DEPUTY ADMINISTRATIVE MGR.
David E. Dunahay

DIV. OF SECURITY MANAGEMENT
Manager - Robert L. Windus

DIV. OF SAFETY
Manager - Aubrey A. Stanford
Asst. Mgr. - John W. Bomar

DIV. OF ENVIRONMENT
Manager - Anthony R. Morrell
Asst. Mgr. - Nicholas J. Stas

DIV. OF MANAGEMENT ANALYSIS
Manager - Howard F. Perry

DIV. OF PERSONNEL MANAGEMENT
Director - Raymond W. Gunter
Asst. Dir. - Mary L. Herring

DIV. OF ADMINISTRATIVE SERVICES
Director - John E. Kiley

DIV. OF INFORMATION SYSTEMS
Manager - Gary L. Ragsdale
Asst. Mgr. - Larry E. Stewart

Bonneville Power Administration Offices

BPA Headquarters
Public Involvement Office
1002 NE Holladay
Sixth Floor
P.O. Box 12999
Portland, Oregon 97212
503-230-3478
Toll-free lines:
Oregon—800-452-8429
Other Western States—
800-547-6048

Lower Columbia Area
1500 Plaza Building, Suite 288
1500 NE Irving Street
P.O. Box 3621
Portland, OR 97208
(503) 230-3490

Eugene District Office
US Federal Building
Room 206
211 E 7th Street
Eugene, OR 97401
(503) 687-6952

Upper Columbia Area
US Court House, Room 561
W 920 Riverside Avenue
Spokane, WA 99201
(509) 456-2515

Wenatchee District
Morris Building, Suite 117
23 S Wenatchee Avenue
PO Box 741
Wenatchee, WA 98801
(509) 662-4377

Montana District
800 Kensington
Missoula, MT 59801
(406) 329-3060

Puget Sound Area
415 First Avenue N, Room 250
Seattle, WA 98109
(206) 442-4130

Snake River Area
W 101 Poplar
Walla Walla, WA 99362
(509) 522-6226

Idaho Falls District
531 Lomax Street
Idaho Falls, ID 83401
(208) 523-2706

Boise District
Federal Building, Room 376
550 W Fort Street
Boise, ID 83724
(208) 334-9137

Washington, DC Office
Bonneville Power
Administration
Forrestal Building
Room 8G033
Washington, DC 20585
(202) 252-5640

Washington Public Power Supply System Office
3040 George Washington Way
PO Box 968
Richland, WA 99352
(509) 372-5750

DOE/BO-604
February 1986
2.5M