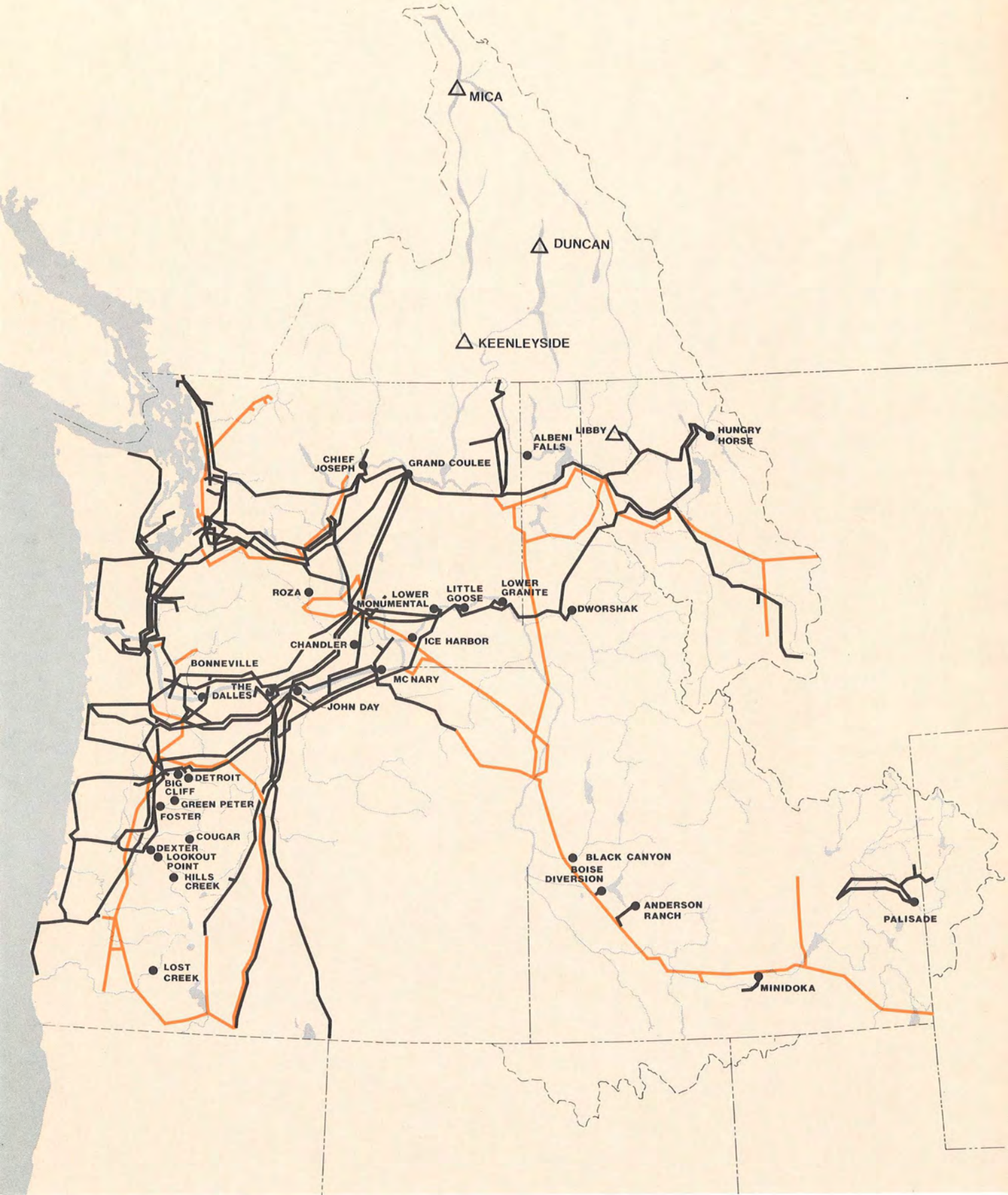
1977 Annual Report

U.S. Department of Energy
Bonneville Power Administration

Pacific Northwest Power System

Major Facilities Existing and Under Construction

Major BPA Transmission Facilities
Major Non BPA Transmission Facilities
Federal Hydroelectric Dam
Columbia River Treaty Dams



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Federal Columbia River Power System

U.S. Department of Energy

James R. Schlesinger
Secretary

Bonneville Power Administration

Sterling Munro
Administrator

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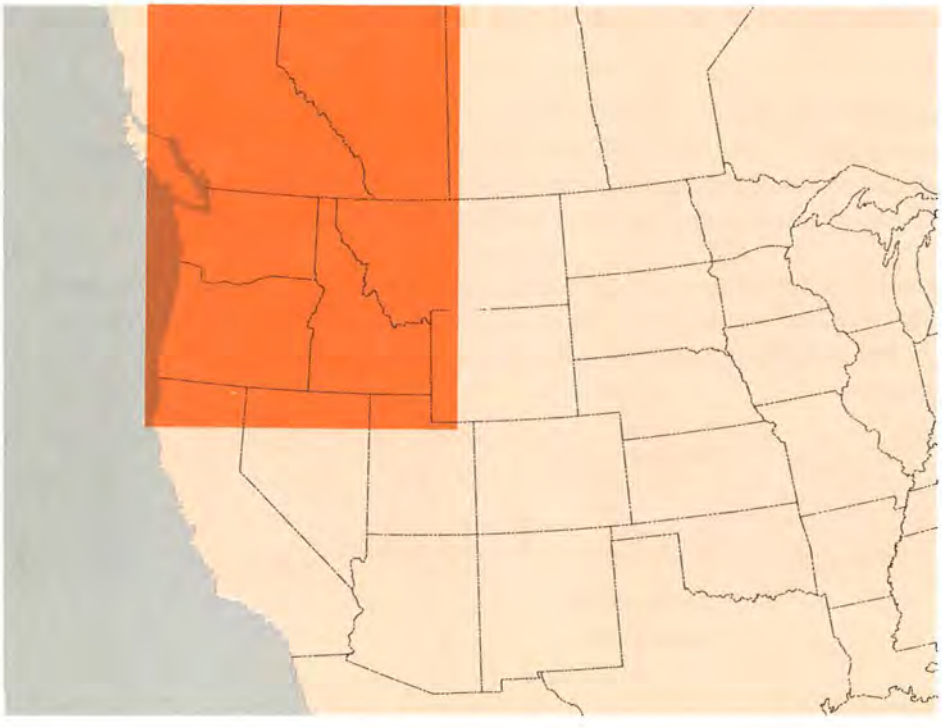


Insert shows area covered by PNW Power System Map inside front cover.

Cover photo: Lineman uses insulated "hot stick" to perform maintenance on BPA transmission line.

Letter to the Secretary

January 2, 1978

Honorable James R. Schlesinger
Secretary of Energy
Washington, D.C. 20545

Dear Mr. Secretary:

This is the Bonneville Power Administration's 40th Annual Report on the Federal Columbia River Power System. It covers events of fiscal year 1977 plus significant developments since the fiscal year ended on September 30.

I am pleased to report that the near-term power outlook in the Pacific Northwest appears promising. More importantly, electric energy users in this region are showing a growing concern for and an adherence to prudent energy practices in their daily lives.

Fiscal year 1977 was marked by the most severe drought in Pacific Northwest history, which had a direct impact upon the region's hydroelectric power supply and the ability of the Federal System to serve its loads. Consequently, BPA secondary energy – including interruptible power to its industrial customers – was curtailed for nearly the entire fiscal year. In addition, almost no surplus energy was shipped out of the region during this period, and a number of Northwest utilities had to import higher-cost energy and impose temporary surcharges on their customers.

As a result of the drought, Federal Columbia River Power System revenues were some $96 million below those forecasted at the start of the fiscal year. Gross revenues of $223.6 million were 25 percent below those of FY 1976, and net revenues declined from the record $67.1 million surplus in FY 1976 to a record deficit of $55.9 million in FY 1977. BPA's initial borrowing under its self-financing authority, in the form of a $125 million, 1-year cash advance on September 30, 1977, was partially attributable to the drought-related drop in power sales.

The drought itself was alleviated, however, by heavy precipitation throughout the region in late 1977. It now appears that 1978 will see a recovery of regional reservoir levels and near-normal electric service to all customers, including the restoration of secondary deliveries and sales of surplus energy later this year. Gross revenues of $301 million are projected for FY 1978.

The longer-range electric outlook in the Pacific Northwest is more ominous. Downward revisions in regional load forecasts are more than matched by continuing delays in the licensing and construction of planned thermal generation. Based upon critical water conditions, we are now facing at least 11 years of potential electric energy deficits. Since it is not realistic to expect a speed-up in generation construction, these deficits can only be averted by a combination of mild weather and improved energy conservation.

The overriding energy concern in the Pacific Northwest, however, is the continuing need for a consensus plan which will resolve a number of crucial issues facing power planners throughout the region. Various plans have emerged during the past year, two of them in the form of legislation introduced in the Congress. All of these have certain common elements, and I am hopeful that a compromise program satisfactory to all concerned parties will be enacted during this fiscal year.

I embark upon my tenure as the eighth Bonneville Power Administrator with a keen appreciation of the competence and strong dedication of the BPA staff. I also wish to express my sincere appreciation to you and to your colleagues in the new Department for your support of our program. We in Bonneville Power Administration look forward to working closely with you in fashioning a viable energy program for this region and the nation.

Sincerely,

Sterling Munro
Administrator

Regional Perspective

Despite intensive efforts over the past year, no consensus plan was formulated to assure the Pacific Northwest an adequate power supply in the future. Meanwhile, planned thermal generation continued to experience delays and increasing costs. Fiscal Year 1977 also marked the most severe drought in recorded Northwest history — an ironical introduction to a decade of anticipated electric energy deficits.

Regional Load Forecasts Vary

The possibility of regional power shortages and their severity is closely tied to what load forecast is accepted as a measuring stick. Traditionally power supply planning in this region has been based upon utility forecasts compiled by the Pacific Northwest Utilities Conference Committee. The 1977 PNUCC forecast for the period 1977-78 through 1987-88 shows substantial energy deficits in every one of the 11 years based on critical water conditions and yearly load growth averaging 4.5 percent.

With the increasing public concern about energy planning, parties other than utilities now take an active interest in load forecasting and its implications. The Northwest Energy Policy Project, a 2½-year planning study sponsored by the Pacific Northwest Regional Commission, issued its load forecasts for Idaho, Oregon and Washington in November 1977. Under three growth-rate scenarios, the NEPP study estimates average yearly load growth of 1.43, 2.93 and 4.38 percent during the period 1974-2000.

An even lesser rate of regional load growth is predicted in a study entitled "Choosing an Electrical Energy Future for the Pacific Northwest: An Alternative Scenario," which was conducted by two staff members of the Natural Resources Defense Council. Based upon the premise of stringent electric energy conservation, the NRDC study estimates that the power requirements forecasted by the PNUCC could be reduced by 40 percent by 1985, and by nearly 60 percent by 1995.

Other forecasts issued by State agencies, universities, consultant firms and public interest organizations generally fall within the broad spread of the above load growth projections. Pending the development of some agreed-upon load forecasting mechanism, electric energy planning in the Pacific Northwest will be a subject of growing controversy.

Regional Drought

As a harbinger of the power shortages anticipated in coming years, the worst drought of Northwest record drastically restricted the production of hydropower in FY 1977.

Following two of the best water years of record, regional hydroelectric reservoirs were essentially full in mid-September of 1976. But as fall advanced into winter, Mother Nature withheld her usual bounty of rain and snowfall throughout the Columbia Basin. By the spring of 1977, measuring points around the region had recorded precipitation levels well below any previously experienced. For example, at Vancouver, Washington, where precipitation records have been maintained for 128 years, the 1976-77 winter rainfall amounted to only 50 percent of the previous low of record.

When the possibility of a meager water supply became apparent, Bonneville Power Administration discontinued deliveries of interruptible energy to its direct-service industrial customers and secondary energy sales to investor-owned utilities on November 1, 1976. Secondary energy sales to public agencies were discontinued a month later. To compensate for the loss of interruptible energy, the industries obtained other classes of energy from or through BPA, imported more costly power from outside the region, and cut back on their total energy use. By early March 1977, the Northwest aluminum industry, for example, curtailed production by nearly 20 percent, and more than 600 aluminum workers were laid off. A number of Northwest utilities had to import high-cost energy to offset their drought-caused generation shortages and the lack of BPA secondary energy, and special drought surcharges were imposed on their ratepayers.

The impact of the drought on power resources was somewhat mitigated by regional loads underrunning utility forecasts by 3-4 percent in the spring of 1977, with savings of 7-9 percent during the summer and fall. This load underrun is generally ascribed to mild weather, a somewhat depressed economy and voluntary curtailment. The latter was initiated by a joint appeal from the Northwest utilities and BPA in February 1977 urging the public to reduce electric energy use by 10 percent.

Nevertheless, by the end of July 1977 when system reservoirs are normally full, the hydroelectric storage deficiency measured 12.7 million acre-feet of water. This translates to a power deficit of 14.1 billion kilowatthours of energy or 30 percent below normal reservoir levels at the end of the spring runoff.

Curtailment Guidelines Approved

One of the benefits of the 1976-77 Northwest drought was that it stimulated regional planning to meet water shortage conditions. Early in 1977 the Governors of Idaho, Montana, Oregon and Washington formed an electric energy task force to assess the drought's impact and to develop recommendations to counter it. As a result, in August 1977 the four Governors adopted guidelines for increased voluntary and mandatory curtailment. These "Regional Guidelines for Curtailment Planning" provide for a sequence of actions to meet a progressively worsening electric energy shortage — from voluntary cutback appeals to controlled rotating blackouts.

Other water uses were also jeopardized by the low streamflows. In addition to constraints on irrigation and water recreation, the Columbia River anadromous fishery was seriously threatened. In the early spring of 1977 the Governors of Idaho, Oregon and Washington called upon river management agencies to provide adequate streamflows for downriver fish migration. The result was "Operation Fish Flow '77," in which water was released from various dams to create an artificial freshet for the young fish. Some of this water was released over dam spillways and represented an irretrievable loss of electric energy, but most of it was used to generate

Public workshop participants in Seattle consider issues raised in BPA's Role Environmental Statement. (right)

Sterling Munro is sworn in as the eighth BPA Administrator by Senior U.S. District Court Judge Gus J. Solomon. (left)

Small group discussion of alternatives for future power generation creates interest at a BPA workshop in Olympia, Washington. (far right)

power. This resulted in some temporary overgeneration, even though thermal generation was cut back as part of a cooperative strategy involving Federal dam operators, utilities, fishery agencies and BPA. Most of the excess power was "stored" with utilities in adjoining regions for later return to the Pacific Northwest. Even with these arrangements, spilled water and transmission losses cost the region some 260 million kilowatthours of electric energy. On the positive side, it is believed that Operation Fish Flow '77 averted the potential destruction of entire fish runs.

Return of Normal Weather Alleviates Drought

To the relief of Northwest water users, a seemingly normal weather pattern returned to the region in the fall of 1977. Heavy precipitation in late November and early December enabled the Northwest Power Pool and BPA, on December 7, to rescind their earlier call for 10 percent voluntary curtailment. By the end of the calendar year the probability of refilling the region's hydroelectric reservoirs in 1978 appeared to be favorable.

Power Supply Planning

Fiscal Year 1977 saw the power supply of the Pacific Northwest become a burning public and political issue. At the very center of a growing controversy over the distribution, cost and further development of the region's electric energy resources was Bonneville Power Administration.

A number of vexing problems with regard to the Northwest power supply have been simmering, some of them for years. The seeming inability of the electric utility industry to formulate a successor plan to the Hydro-Thermal Power Program has brought these problems into sharp focus. Contributing to the sense of crisis are the continuing delays and spiraling costs of new generation, and BPA's inability to implement new power programs until it complies with court orders by completing certain environmental statements.

As described earlier, few energy subjects are as contentious as load forecasting. Yet even the most conservative estimates of Northwest power requirements in the early 1980's are likely to be unmet with critical water conditions. Some scheduled thermal powerplants have been delayed several years — delays resulting from lengthy siting and licensing procedures, modified technical requirements, and for other reasons. But whatever the causes, a slippage in plant schedule adds substantially to the ultimate cost of a plant and the rates to be charged for its output.

While all Northwest utilities are experiencing upward pressures on their rates, the investor-owned firms — most of whose contracts for firm Federal power expired in 1973 — have been hardest hit. Two-thirds of the low-cost hydropower marketed by BPA goes to Washington State, where public systems and cooperatives have long been dominant. By comparison, the large majority of power users in Idaho, Oregon and Montana are served by investor-owned utilities which are increasingly dependent upon high-cost thermal resources.

Another huge question is the future of BPA's direct-service industrial customers in the Pacific Northwest. This industrial load — predominantly that of six aluminum firms — currently represents about one-third of BPA sales. Most of the contracts with industry expire in the 1980's and almost certainly will not be renewed, at least in their present form. BPA has notified its preference customers that it will be unable to meet their load growth requirements after 1983. Consequently, both existing and newly forming preference customers are expected to lay claim to the industrial power as contracts expire. How the industries will replace this power — and at what cost — pose a major dilemma for both the industries and the region as a whole.

Rate differences...the demands of existing and new preference customers... investor-owned utilities' and heavy industries' stakes...these are but parts of the region's electric energy puzzle. Who should be responsible for load forecasting and its validation? Can future generating facilities be sited, financed and constructed more cheaply and expeditiously than at present? How should their power be distributed and priced? What energy conservation standards should be adopted and enforced, and by whom?

Fiscal Year 1977 saw all of these concerns come to the fore. Individually and collectively, they have become the subjects of wide publicity and intensive debate. Nor is this dialogue limited to BPA and its customers. State and local governments have become actively involved, as have environmental and other public interest groups.

This Annual Report cannot begin to catalog, let alone describe, the multitude of proposals which have come forth over the past year with regard to the region's power supply system. However, among the salient proposals are: 1) the Pacific Northwest Electric Power Supply and Conservation Act, proposed by the Pacific Northwest Utilities Conference Committee (PNUCC) and introduced "by request" in both houses of Congress; 2) a bill introduced in the House of Representatives by Oregon Congressman Jim Weaver to create a Columbia Basin Energy Corporation; 3) the "alternative energy scenario" developed by staff of the Natural Resources Defense Council; 4) the Oregon Domestic and Rural Power Authority proposed by Oregon's Governor Bob Straub; and 5) a regional proposal by the Portland Commissioner of Public Utilities, Frank Ivancie, to benefit domestic and rural consumers.

City of Portland Lawsuits

On November 14, 1977, the City of Portland filed two separate lawsuits against BPA in the U.S. District Court for the District of Oregon. In the first of these, the City challenged BPA's interpretation of the "preference clause" and its methods of allocating Federal power, and requested the court that the City be declared to be a BPA preference customer. The second lawsuit challenged the validity of power sales contracts and net billing agreements which BPA has executed since January 1, 1970, the effective date of the National Environmental Policy Act, without preparing environmental impact statements.

Congressional Hearings

A series of five Congressional hearings held in Oregon and Washington in December 1977 focused attention on the various concerns and viewpoints with regard to regional power supply planning and the role of BPA. These public hearings of the House Subcommittee on Water and Power Resources, chaired by Representative Lloyd Meeds of Washington, elicited testimony on the legislative proposals before Congress which were developed by the PNUCC and by Representative Weaver. They also provided a forum for a broad cross section of opinions on how the region should structure its power supply network.

While no consensus emerged from these hearings, they served to demonstrate a sense of urgency in pursuing a regional accommodation. In this regard, the situation in the Pacific Northwest parallels the national effort to formulate a comprehensive strategy for solving the energy dilemma.

BPA began marketing power from Lost Creek Dam in southwestern Oregon, its 30th Federal power source, in December 1977. (Photo courtesy of Army Corps of Engineers)

Pilings for controlling water currents were left high and dry for most of the 1976-77 operating year as a severe drought gripped the Pacific Northwest.

BPA Overview

On October 1, 1977, the Bonneville Power Administration transferred to the newly formed Department of Energy. This changeover took place just 6 weeks after the 40th anniversary of BPA's creation as a "project" under the Secretary of the Interior.

Role EIS

One of the first tasks confronting BPA during its transition into the new Department is that of completing its "role environmental impact statement." As previously reported, this comprehensive document has been in preparation since late 1975. It examines a breadth of BPA activities and how they relate to the regional power system, as well as considering alternative roles which BPA might play in the future.

The resulting product — including a supplemental EIS on serving the proposed Alumax aluminum reduction plant — is a 6-volume, 3,100-page draft document whose preparation had cost $2.6 million when it was filed with the President's Council on Environmental Quality (CEQ) in August 1977.

Entitled "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System, Including Its Participation in the Hydro-Thermal Power Program," this programmatic environmental statement and planning report consists of five parts. The first two describe the regional power system and BPA's function within it. Three appendices provide detailed information on BPA's power resources, acquisitions, planning and operation; its power transmission; and its power marketing activities. A sixth volume contains the "site specific" EIS dealing with the various impacts of providing electric service to the aluminum plant proposed to be built by Alumax Pacific Corporation near Umatilla, Oregon.

Because of the large investment in the draft document, its encyclopedic treatment of a broad subject, and the important issues and alternatives raised, it was decided that it ought to be subjected to wide public review and comment. Accordingly, BPA launched an intensive regionwide public involvement program when the draft Role EIS was issued in early September 1977. This $500,000 program included widespread publicity and advertising to acquaint the general public with the kinds of issues involved, and with the need for broad participation and input.

During the 3-month period from mid-September to mid-December, 28 public meetings were held in 12 cities throughout Idaho, Oregon, Washington, and western Montana. Later, at the request of various parties including the Governor of Montana, the public comment period was extended for an additional 60 days and two public meetings were scheduled in eastern Montana.

When the original schedule was completed in mid-December, more than 2,500 people had participated in the public meetings. In addition, telephone information was provided to some 1,100 callers. Nearly 300 verbal statements were recorded at the meetings and several hundred written comments were received by the end of the year.

As might be expected, these included a wide variety of substantive input, some of it critical of the Role EIS, its structure, and its treatment of the numerous issues addressed. The BPA staff is now engaged in responding to these comments, incorporating them into the final document, and revising the latter to update its contents and to accommodate the viewpoints expressed. The final Role EIS is scheduled to be completed and filed with CEQ by late 1978.

If the Role EIS is the most comprehensive such document ever published in the Pacific Northwest, it is also unprecedented in the public involvement which was accorded it. It is to be hoped that this entire process will accomplish three salient objectives. First, the Role EIS and its reception should assist BPA and other entities in the region to formulate major policies and courses of action. Second, the public awareness and interest generated by the program should have a carryover effect. And finally, the final Role EIS should serve as a valuable reference document and a point of departure for regional electric energy planning for decades to come.

1979-81 Rate Increases

A second major project in which BPA is involved is to carry out a broadbased review of its rate structure in preparation for a substantial increase in wholesale power rates proposed to take effect on December 20, 1979. This will be only the third rate increase in BPA history, and by far the largest. The others were a 3-percent increase in 1965 and an increase averaging 27 percent in 1974. BPA has also obtained interim approval of a 22-percent increase in its transmission service (wheeling) rates.

Present estimates are that BPA will require an 80- to 90-percent increase in annual revenues commencing in December 1979, with a subsequent increase of about 20 percent beginning in July 1981. Normal escalation in the costs of doing business is of course a factor in the need for greater revenues. The preponderance of the proposed 1979-81 rate increases, however, is attributable to the acquisition of thermal energy from four large nuclear powerplants under net-billing agreements. It is estimated that nearly three-quarters of the needed revenue increase is due to these higher-cost power acquisitions.

Under the agreements, BPA will acquire the total capacity of two nuclear plants being built by the Washington Public Power Supply System (WPPSS) on the Hanford Reservation in southeastern Washington. It will also acquire 70 percent of the capacity of a WPPSS nuclear project to be constructed near the Washington coast. And BPA has been receiving 30 percent of the output of Trojan Nuclear Project near Rainier, Oregon, since that facility began commercial operation in early 1976.

Trojan was licensed and built before the inflation spiral steepened and other factors exerted complex pressures on the nuclear industry. Consequently it was completed for about $460 million and without substantial delays. The three WPPSS projects, on the other hand, have been plagued by rapid cost escalation and schedule slippages of up to 3 years. The total cost of the latter three is now projected to be $3.9 billion. These construction delays and increasing costs parallel those of most nuclear and coal-fired powerplants presently under development throughout the nation.

Annual Rate Adjustment Sought

Under the terms of its power sales contracts, BPA can adjust its rates only at 5-year intervals. It is, therefore, seeking to amend this contract provision to permit a second rate increase in July 1981 and annual adjustments thereafter. In October 1977 letters were sent to all BPA customers seeking approval to amend contracts so that smaller rate adjustments could be imposed at more frequent intervals. Based upon responses to date, the great majority of BPA customers are expected to approve the contract amendment.

It should be emphasized that, in developing the new rate schedules for 1979 and 1981, BPA will investigate various pricing concepts. Among the factors to be considered are conservation, environmental protection, consumer understanding and acceptance, ease of administration, and stability and continuity. The comprehensive rate review will be aimed at generating maximum public involvement and input. This will include the preparation and public review of an environmental impact statement.

Interim Wheeling Rate Increase Granted

Traditionally the BPA Administrator has set the rates for "wheeling" non-Federal power over the BPA transmission system. The Federal Columbia River Transmission System Act of 1974, however, stipulates that BPA wheeling rates be filed with the Federal Power Commission for review and approval.

Consequently, on July 30, 1976, the Secretary of the Interior filed BPA's proposed transmission rate schedules with the FPC. These schedules provided for an average increase of 22 percent. Subsequent intervention by several BPA customers led to a request for an interim rate increase while various issues are being resolved.

In view of the lengthy approval process, the Secretary requested and the FPC granted the 22-percent increase on an interim basis for the period July 1977 through June 1978. With the dissolution of the Federal Power Commission as part of the overall reorganization creating the Department of Energy, the latter's Economic Regulatory Administration now has jurisdiction over the matter.

Allocation Formula to be Developed

As previously mentioned, there is a growing demand for the power marketed by Bonneville Power Administration. Even with the power scheduled to enter the Federal system as net-billed thermal generation comes on line, BPA has notified its preference customers that it may not be able to accommodate their load growth after mid-1983. Most contracts with direct-service industrial customers will expire in the 1980's, and the latter have been informed that these contracts cannot be renewed, at least in their present form. In addition, several new public bodies have applied for power, and other such bodies may be formed.

Night view at Grand Coulee Dam shows third powerplant in background and transformer deck in the foreground. (Photo courtesy of U.S. Bureau of Reclamation)

To date there is no regional consensus on how to apportion the Federal power supply, nor does BPA have statutory authority to develop or acquire significant new energy resources. Unless and until Congressional legislation is enacted to change this situation, BPA must devise an allocation formula which will address — but probably not satisfy — all of the competing requirements of its existing customers, newly forming entities, and the various States.

Many variables and alternatives will be considered in selecting a proposed formula. These will include the class of customer served, customer-owned generation, type of load, grades of energy and their rates, and energy conservation.

These deliberations will take place in the public arena. Every ratepayer in the Pacific Northwest has an important stake in this process. Since current BPA contracts begin to expire in 1981, it is essential that an allocation formula be publicly debated and adopted by mid-1980 at the latest.

Energy Conservation Program Expands

During Fiscal Year 1977 the need for energy conservation was dramatized by the prolonged drought which gripped the Pacific Northwest. Current projections of regional loads and resources point to a continuing threat of power shortages in coming years. Nor is the development of more generation, with its long leadtimes, escalating costs, and unavoidable impacts on the environment, a stand-alone option. It must be teamed with energy conservation — the quickest, most economical and cleanest energy resource now available.

BPA continued to expand its energy conservation program during the past year. To encourage improved building insulation, BPA initiated a series of aerial flyovers of selected Northwest communities in the winter of 1976-77 in cooperation with local utilities. Infrared photographs taken on clear, cold nights identified buildings with excessive heat loss. The utilities then followed up with their customers to point out the advantages of installing insulation. This aerial infrared flyover program will be expanded to some 35 utility service areas in early 1978.

Based on the premise that energy conservation is much less expensive than developing thermal generation, BPA conducted an innovative study during FY 1977. The thrust of the study was that cost-effective building insulation can offer substantial savings for both utilities and their customers, and thereby enable BPA to hold down its wholesale rates. Accordingly, a preliminary plan was designed whereby BPA might finance insulation to be installed in under-insulated electrically heated residences served by preference customer utilities throughout the Northwest. Working through these utilities, BPA would finance the insulation, with part of the investment cost to be repaid over a 3-year period from electricity savings.

This proposal was submitted by BPA to both the Department of the Interior and to the newly formed Department of Energy, as well as being brought to the attention of Congressional committees. Further analysis and refinement of the proposed program would be required to make it consistent with energy legislation now before Congress. In addition, BPA may require Congressional authorization to expend funds on this new but promising conservation activity.

Maintenance crew repairs segment of the San Juan Island submarine cable.

Young students learn about electrical equipment on BPA motivational tour.

Another energy-saving project undertaken during the year was a prototype energy retrieval system which was installed in a substation at the BPA Ross Complex in Vancouver, Washington. Heat from the transformers is used to warm adjacent buildings, while a solar roof collector provides supplementary heating and air conditioning.

In a related effort, 18 BPA-owned homes at its Midway Substation in central Washington are being used to collect data on residential energy-saving techniques. This project will evaluate both the technical and lifestyle aspects of energy conservation and alternative energy processes. Facets of the study include home energy management, solar heating, weatherization, and heat pumps.

BPA is continually expanding its sponsorship of and active participation in numerous energy conservation conferences and public exhibit programs. Periodic seminars are held for BPA employees to familiarize them with home energy management and "do-it-yourself" installation of insulation/weatherization and solar devices. And throughout the BPA transmission system, physical facilities and operating techniques are being modified and upgraded to effect energy savings.

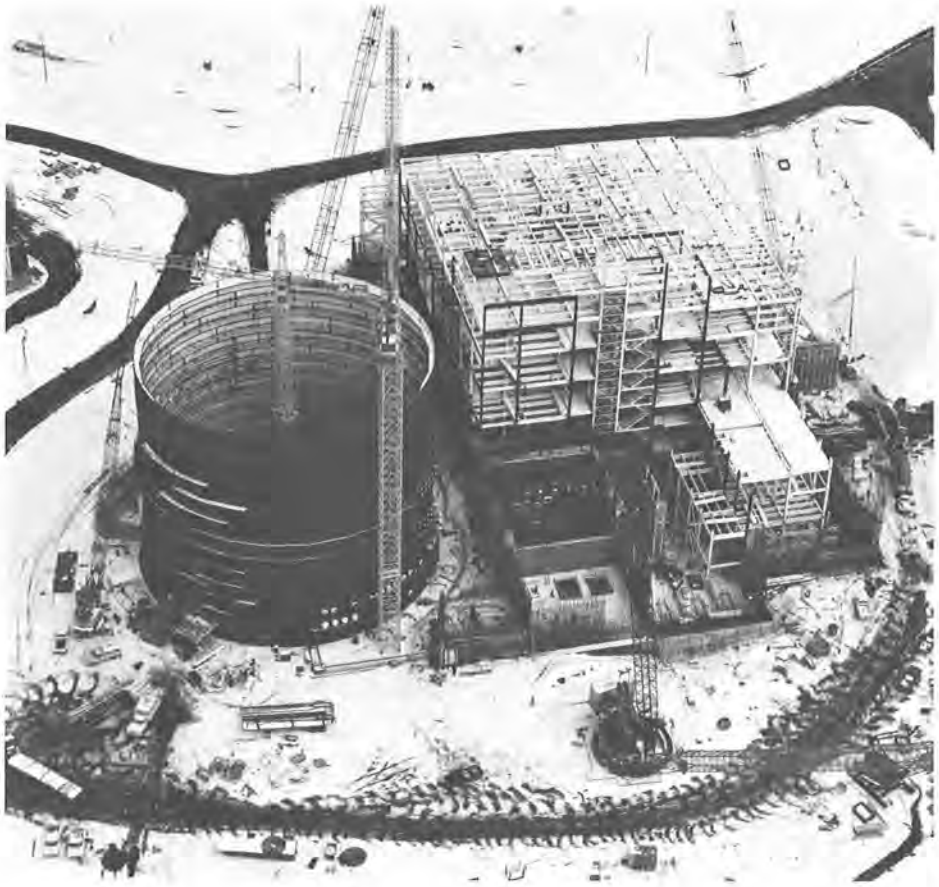
In the coming fiscal year BPA will introduce a substantially broader and more aggressive program of energy conservation incentives and applications. As with its rate review and allocation proposals, this conservation program will involve maximum participation on the part of the general public. The experience of the past year is a basis for building strong regional support for energy conservation which could serve as a model for other parts of the nation.

Status of Litigation

From 1954 to September 30, 1977, BPA's legal services were provided by the Portland Regional Solicitor's Office of the Department of the Interior. With the transfer of BPA to the Department of Energy, a portion of Interior's legal staff was also transferred to DOE. These personnel in turn were assigned by DOE to Bonneville Power Administration, and constitute the Office of General Counsel originally provided for in the Bonneville Project Act.

The new legal unit does not suffer from a lack of business. As mentioned in the first chapter of this Annual Report, the City of Portland filed two lawsuits in November 1977 which challenge BPA power marketing policies and a large number of contracts and agreements executed and amended since 1970. In addition, several lawsuits initiated in earlier years are still awaiting final determination.

The signing of a power sales contract with Alumax Pacific Corporation triggered two lawsuits in April 1975. Although one of these was filed by commercial interests and citizens of Clatsop County, Oregon, and the other by a consortium of environmental groups, both essentially challenged BPA's participation in Phase 2 of the regional Hydro-Thermal Power Program as not complying with the National Environmental Policy Act of 1969 (NEPA). The first of these lawsuits is commonly referred to as the "Alumax case," and the second as the "NRDC case," in recognition of the Natural Resources Defense Council, one of six plaintiffs.



Washington Public Power Supply System Nuclear Plant No. 1 (WNP-1) takes shape on the U.S. Hanford Reservation in eastern Washington. (Photo courtesy of Washington Public Power Supply System)

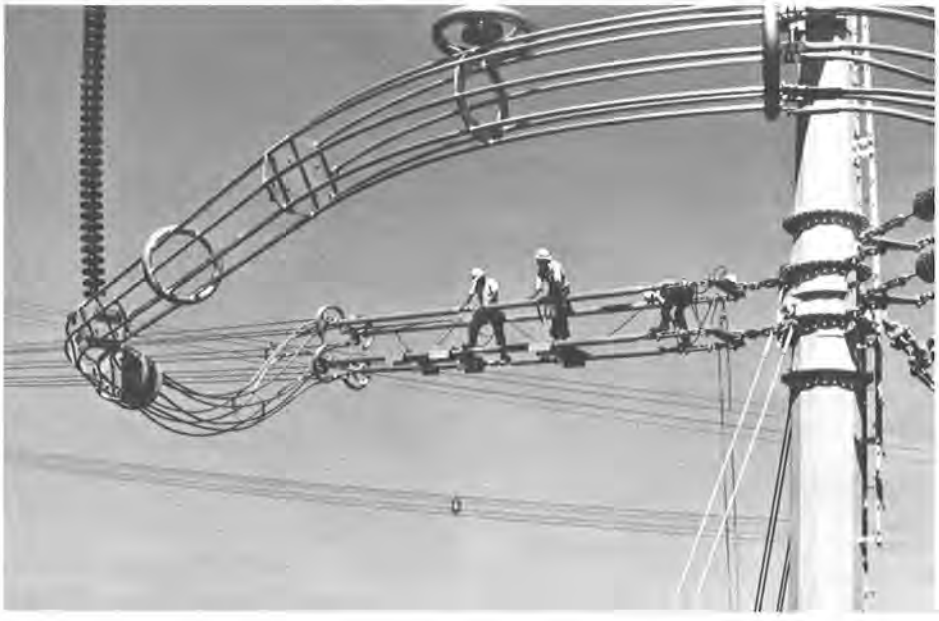
Both cases were decided in favor of the plaintiffs. In September 1975 the U.S. District Court for the District of Oregon issued a judgment on the Alumax case. Holding the Alumax contract to be "valid but unenforceable" pending the completion of a BPA site-specific EIS on its proposed service to an aluminum reduction plant to be built in northeastern Oregon, the court also required BPA to show the relationship of the Alumax contract to its participation in Phase 2. An appeal was entered in November 1975, and the Ninth Circuit Court of Appeals has scheduled oral arguments to be heard in January 1978.

In July 1977 the court entered its opinion that NRDC and its co-plaintiffs were entitled to a summary judgment declaring that BPA was required to file an EIS concerning Phase 2 of the Hydro-Thermal Power Program.

Two lawsuits involving transmission rights-of-way were settled in BPA's favor during the past year. The first of these, regarding service to an Aluminum Company of America magnesium-ferrosilicon plant near Addy, Washington, was decided by the Ninth Circuit Court of Appeals in late 1976. Its three-part opinion held that BPA had not violated NEPA in contracting to serve the plant, and that a BPA environmental statement covering the proposed transmission facilities was adequate. However, the court did require that BPA prepare an EIS on the construction and operation of the ALCOA plant before completing construction of the transmission line. The EIS was filed in August 1977 and the injunction was lifted the following month, which permitted BPA to complete the project and begin providing full electric service to the plant in October 1977.

The second lawsuit involved a proposed transmission line from the Lower Monumental Dam on the Snake River to a BPA substation to be built on the Hanford Reservation near Richland, Washington. It was brought by a group of landowners known as the Columbia Basin Land Protection Association, who oppose BPA plans to construct a portion of the 500-kilovolt line across irrigated farmland. In April 1977 the U.S. District Court in Spokane, Washington, ruled in favor of BPA on all issues except for a requirement that BPA obtain right-of-way permits from two Federal agencies in accordance with the Federal Land Policy and Management Act of 1976. A temporary injunction was imposed pending BPA compliance. The injunction was dissolved on December 12, 1977, and a construction contract was subsequently awarded.

Corona forms around high-voltage conductors in BPA laboratory tests.



Linesmen stand astride insulators on deadend transmission tower at BPA's 1200-kilovolt prototype facility near Lyons, Oregon.

Building the Transmission System

During FY 1977 a total of 307 circuit-miles of BPA transmission lines were energized. More than half of these — 207 circuit-miles — operate at 500 kilovolts. Nine substations were also completed, and at fiscal year end the BPA transmission system was comprised of 12,608 circuit-miles of line and 339 substations.

The major transmission facility energized in FY 1977 was the 174-mile, 500-kV No. 1 circuit of the double-circuit Grand Coulee-Raver line. The line integrates new generation being added at the Grand Coulee third powerhouse and provides the added capacity needed to strengthen the electrical ties between the Grand Coulee and Puget Sound areas. The 1-mile, 500-kV Chief Joseph Powerhouse Line No. 5 was also energized. This line integrates new generation being added at Chief Joseph Dam with the BPA system.

BPA contracted for the construction of three major transmission lines during the past year. The first, a $1.9 million contract, calls for building the 33-mile Little Goose-Lower Granite No. 2 500-kV line to bring generation being added at the Lower Snake River dams into the BPA network. The second contract, of $1 million, covers the building of the 17-mile Ashe-Hanford and Ashe-WNP No. 2 500-kV circuits. These lines will integrate the power generated by the Washington Public Power Supply System's No. 2 nuclear plant into BPA's main grid. The 31-mile Shelton-Kitsap 230-kV circuit will be built under a third, $1-million contract. This line will reinforce BPA's transmission system on the Kitsap Peninsula in the Puget Sound area of Washington.

Ashe-Willamette Valley Project Slated for 1980 Completion

BPA also awarded major contracts for the purchase of aluminum conductor and steel for the Ashe-Willamette Valley project, which includes the Ashe-Slatt and the Slatt-Marion 500-kV lines. A total of $16.7 million worth of steel was purchased for these two lines. In addition, $19 million of aluminum conductor was purchased for the Slatt-Marion segment of the project.

The Ashe-Willamette Valley project will provide double-circuit 500-kV transmission from BPA's Ashe Substation on the Hanford Reservation in southeastern Washington to the proposed Slatt Substation near Arlington, Oregon, and from there to the Marion Substation in western Oregon. The Ashe-Slatt line is now expected to be completed in the spring of 1980, and the Slatt-Marion line in the fall of the same year.

Power Sales

The regionwide drought during most of fiscal year 1977 severely restricted BPA sales of electric energy. Over the past decade, power sales had increased by an average 7 percent annually. In FY 1977, however, they dropped to the lowest level in six years. Total BPA energy sales in FY 1977 declined to 61.7 billion kilowatthours — less than 80 percent of the record 77.5 billion kWh sold in FY 1976.

Revenues from sales of capacity during FY 1977 increased 23.5 percent over those of FY 1976.

The average revenue from the sale of energy to all classes of customers was 3.24 mills per kilowatthour. This FY 1977 revenue index was 9.5 percent below the average 3.58 mills per kWh received in FY 1976. (Sales of capacity only and revenues from other services were not included in compiling these figures.) As a direct result of the drought, the supply of BPA energy to its industrial customers was restricted during part of the year. The BPA industrial power rate schedule provides for an "availability credit" when BPA is unable to supply 100 percent of the energy (within the contract demand) desired by an industrial customer. In effect, the availability credit reduces the average cost of energy paid by industrial customers during an operating year with a period of energy restriction.

Preference Customer Purchases Up . . . Most Others Decline

In the Pacific Northwest, BPA preference customers, including public and peoples' utility districts, cooperatives and municipal systems, purchased 33.5 billion kilowatthours of energy and associated capacity during the fiscal year. Preference customer purchases accounted for 54.3 percent of total BPA sales and represented an 8.8-percent increase over such purchases in FY 1976.

BPA sold only 3.2 billion kilowatthours of energy to investor-owned utilities in the Pacific Northwest during FY 1977, a decline of 48.4 percent from the 6.2 billion kWh delivered in FY 1976.

BPA supplied Federal agencies in the Pacific Northwest with 700.3 million kilowatthours in FY 1977, a 10-percent increase over the 637 million kWh delivered the previous year.

Sales to the aluminum industry during FY 1977 totaled 22.2 billion kilowatthours. In FY 1976 the aluminum companies purchased 29.3 percent of all BPA energy sold. Because of the sharp downturn in total sales, aluminum industry purchases represented 36 percent of total BPA sales in FY 1977.

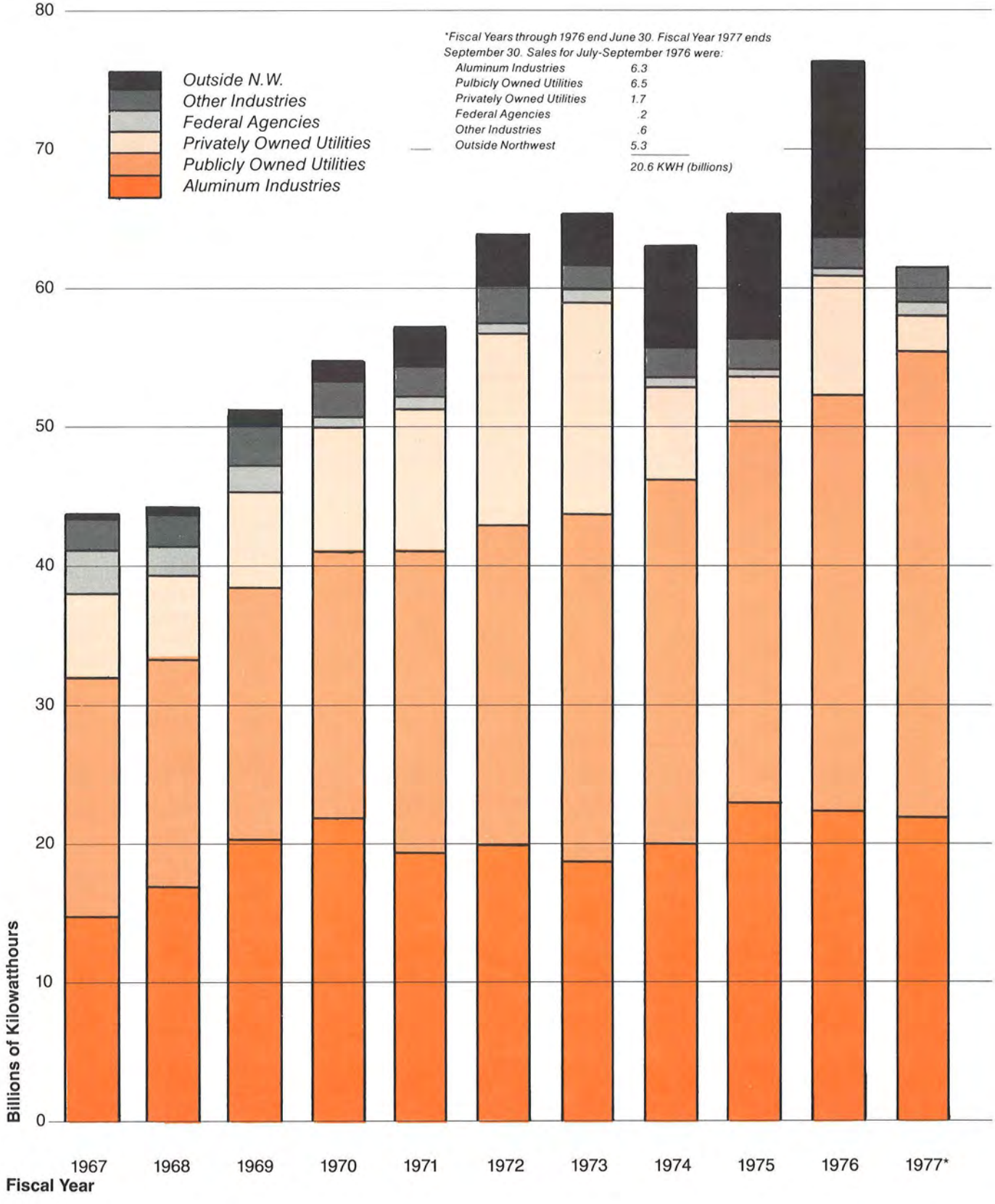
During FY 1977, BPA's other direct-service industrial customers purchased 3.4 percent of BPA's energy, totaling 2.1 billion kilowatthours. This was an 11.6-percent decline from the 2.4 billion kWh delivered in FY 1976.

BPA cut off its deliveries of surplus power outside of the region in September 1976, part of the "transition quarter" between Federal Government fiscal years. No surplus sales were made in fiscal year 1977 — from October 1, 1976, through September 30, 1977. This was in sharp contrast to the 13.3 billion kilowatthours of surplus energy sold outside of the region during FY 1976.

During the transition quarter (July 1 - September 30, 1976) BPA sold 20.6 billion kilowatthours of energy. Of this, 31.4 percent went to preference customers, 8.4 percent to investor-owned utilities, 0.8 percent to Federal agencies, 33.6 percent to industrial customers and 25.8 percent was surplus energy sold outside of the Pacific Northwest.

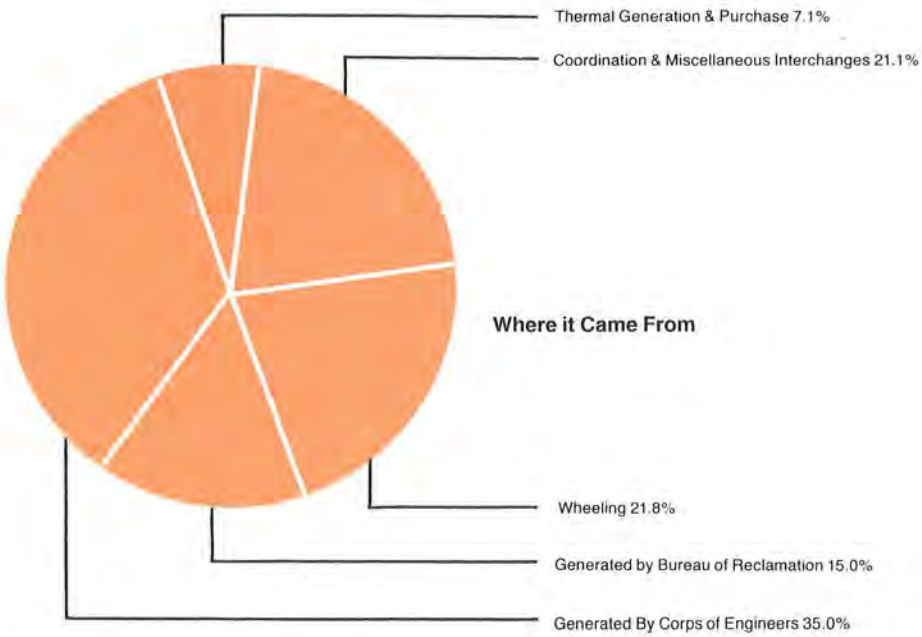
During the past year BPA conducted a series of energy conservation seminars for its employees to assist them in monitoring and cutting back on their energy use. These sessions included exchanging information on home energy budgeting, insulation and weatherization, vehicular energy conservation, and alternate energy systems.

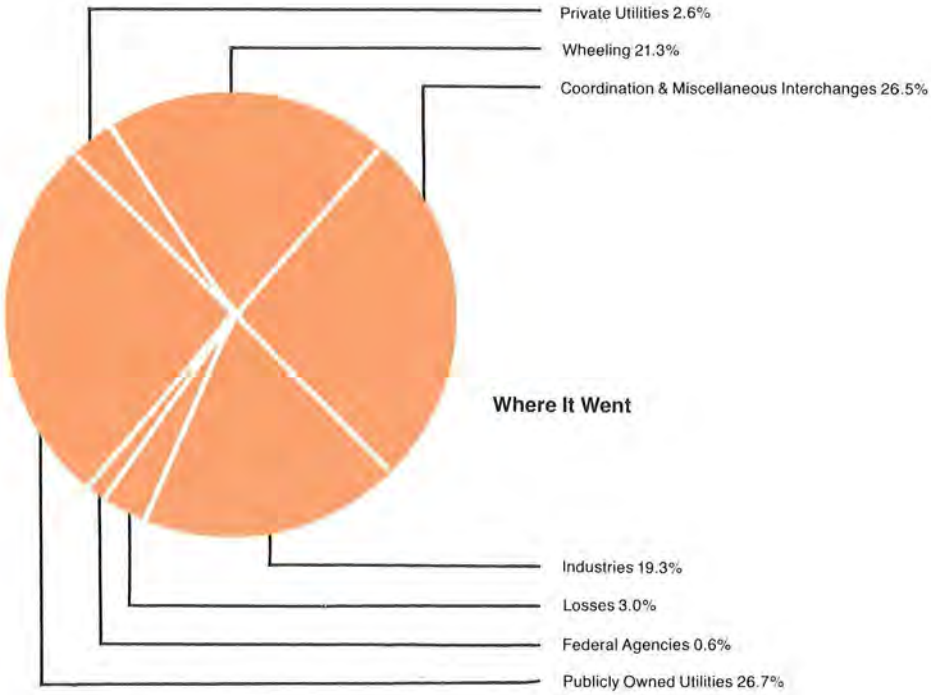
BPA Sales of Electric Energy



Source and Disposition of Total Energy Handled by BPA

Fiscal Year 1977
Total 125.5 Billion Kilowatthours





The Financial Year

Due entirely to the drought, the Federal Columbia River Power System suffered a drastic loss of revenue in FY 1977. Revenues fell $96 million short of the estimate made at the start of the year.

FY 1977 gross revenues of $223.6 million were $73.4 million, or 25 percent, below FY 1976 revenues. This was the first time that revenues failed to show a gain over the previous year since FY 1961 when an economic recession caused a decline. Total expenses for FY 1977, meanwhile, increased by $49.6 million, or 22 percent.

As a consequence, net revenues declined from the record $67.1 million surplus in FY 1976 to a record deficit of $55.9 million in FY 1977. The largest annual deficit previously recorded by the FCRPS was $37.9 million in FY 1974, immediately prior to BPA's last wholesale power rate increase. On a cumulative basis, however, the FCRPS still shows a healthy $329.1 million surplus due to many past profitable years.

FY 1977 marked the most dramatic reversal of year-to-year financial results ever recorded in the 40-year history of the power system. Had there been normal instead of drought conditions, the expected revenue of $319.6 million could have been realized. Revenues would then have netted $40 million more than expenses, which would have represented the second best yearly surplus in the power system's history.

Basis for Financial Reporting

BPA prepares financial statements for the FCRPS on the accrued cost accounting method of financial reporting customarily used by commercial enterprises. Costs include operation and maintenance, the purchase of power, interest, and depreciation of facilities over their useful lives. These financial statements are audited by independent auditors in accordance with generally accepted auditing standards. From FY 1953 through FY 1976, the audit was performed by the U.S. General Accounting Office under the direction of the Comptroller General of the United States. Early in FY 1977, however, the Comptroller General indicated that, because of other workload priorities, the GAO desired to discontinue the FCRPS audit. BPA issued a request for proposals for audit services and as a result selected the firm of Coopers & Lybrand to perform the FY 1977 audit. The complete financial statements with the auditor's opinion appear on pages 17 through 28.

The adequacy of revenues to recover power costs in accordance with statutory requirements, however, is determined by the repayment study which is described later in this chapter.

Revenue and Expense Trends

The drought to some degree affected all categories of revenues. The effect upon secondary energy sales was by far the most dramatic, as secondary sales were curtailed early in the year, and as a result BPA received only a very small amount of revenue from that source. Firm power sales, however, also were reduced due to the combination of mild weather and consumers' response to requests from BPA, the utilities and various governmental jurisdictions to conserve energy wherever possible to mitigate the effects of the drought. As a result, firm power loads were about 7 percent below the start-of-year estimate. Wheeling revenues also were reduced from the expected level as other utilities' energy resources were also restricted and they had less need to use the BPA transmission system. The result, as noted above, was a severe reduction in total revenues.

The increase in expenses, on the other hand, followed the normally expected pattern. Purchased power expense showed the largest percentage gain and reflected primarily the full year operation of the Trojan nuclear plant as contrasted to only partial operation during the preceding year. Operation and maintenance, depreciation, and interest expenses increased primarily in relation to the expanded size of the power system as new facilities were added.

BPA Self Financing

The Federal Columbia River Transmission System Act, which was approved October 18, 1974, placed BPA on a self-financing basis. The Act authorizes BPA to use its revenues to finance its operating costs and to issue revenue bonds to the U.S. Treasury to finance its construction program. To the extent available, revenues also can be used to finance construction. Up to $1.25 billion in bonds are authorized to be outstanding at any time. Because BPA had a substantial balance of unexpended appropriated funds plus use of its revenues when self-financing was first enacted, BPA's cash balance was sufficient to sustain its operations almost through the end of FY 1977. BPA used its borrowing authority for the first time on September 30, 1977, to provide a sufficient cash balance to finance its construction program through FY 1978.

BPA negotiated a memorandum of understanding with the Treasury setting forth the procedures for borrowing. Pursuant to the memorandum of understanding, which was signed on June 15, 1977, BPA sold the Treasury a short-term note with a face value of $250 million. The note permits BPA to obtain cash advances which are repayable within a maximum term of 3 years from the start of the year in which the advance is made. The total advances outstanding at any time are limited to the face amount of the note.

BPA's initial borrowing, which was effective as of September 30, 1977, was in the form of a $125 million 1-year cash advance.

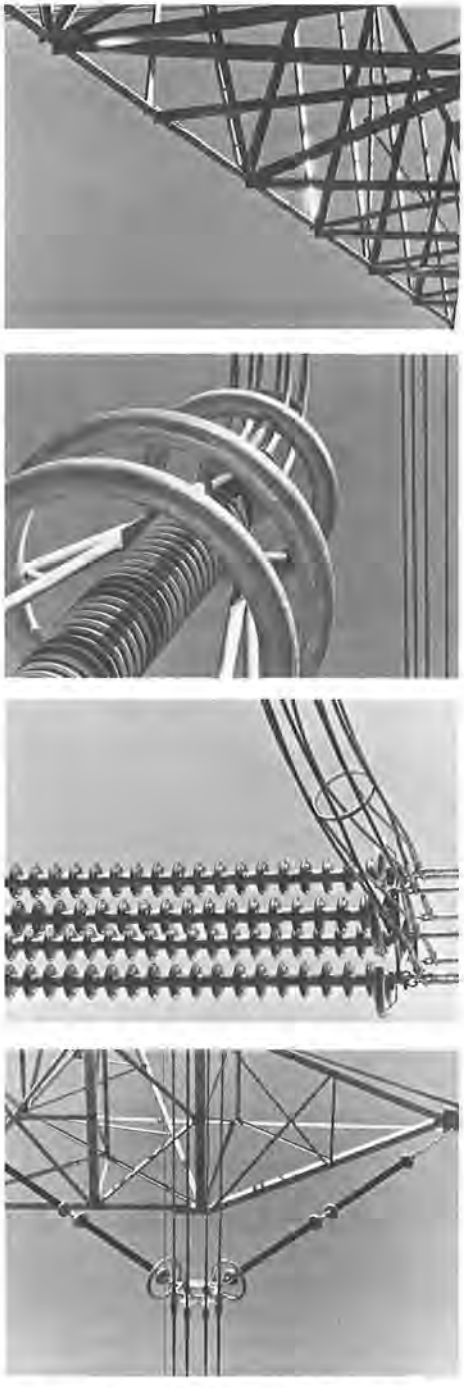
Pursuant to the Transmission System Act, the Treasury sets the rates of interest BPA must pay on its bonds, notes, and cash advances based upon what securities of comparable quality would bear if sold in the open market. The rate the Treasury set on BPA's initial cash advance is 6.73 percent.

Having used up its initial cash surplus, BPA now expects to be borrowing on a regular basis to finance its construction program. The initial cash advance will be repaid with the proceeds from long-term revenue bonds, the first of which are expected to be issued some time during or at the end of FY 1978, depending upon cash needs and the prospects for a favorable long-term interest rate. Additional short-term advances also likely will be used to finance the cost of construction work in progress.

BPA's need to borrow is determined by analysis of its cash position. The BPA cash flow forecast through FY 1980 is shown in the tabulation on page 13.

Future Power and Wheeling Rate Increases

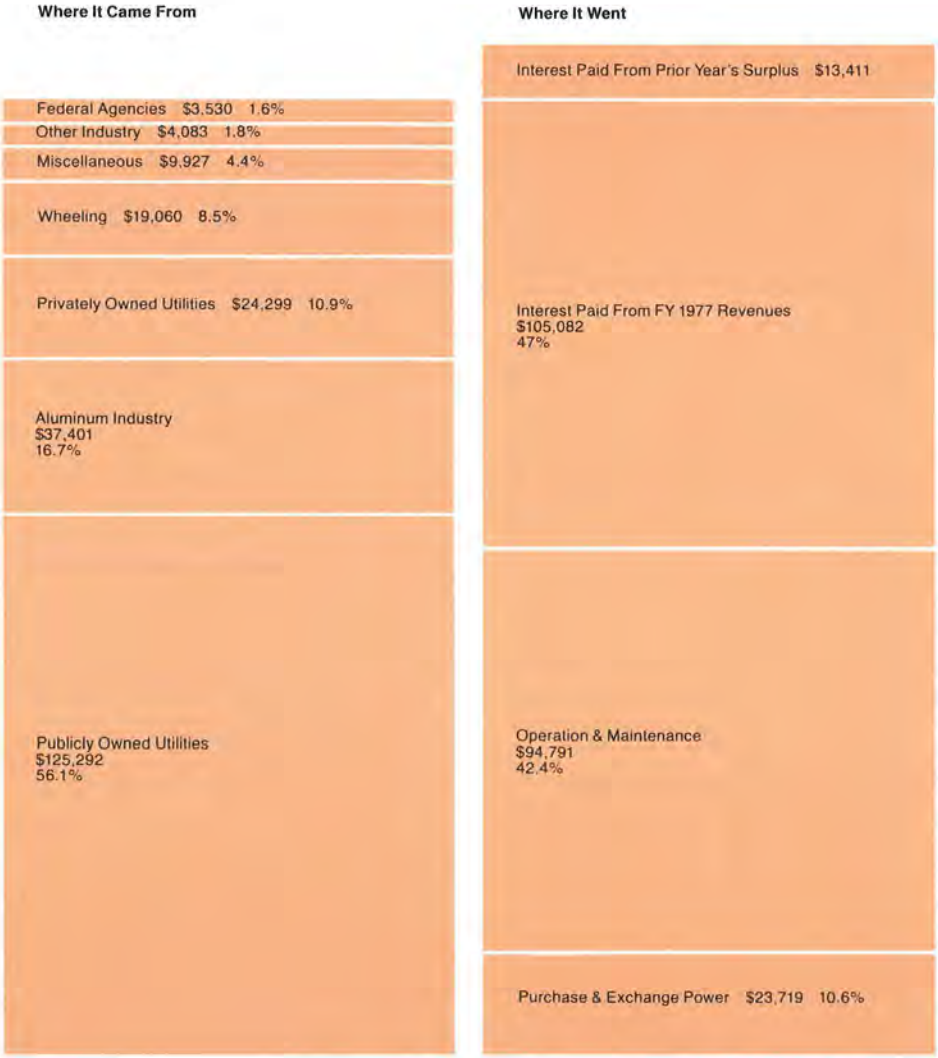
As previously stated, the drought turned what would have been a good financial year into one of the worst of record. The effects of the drought are expected to be temporary, as the odds are that the drought will not be repeated in the years immediately ahead. Other factors, however, are combining to put extreme pressure on BPA revenues, and this will necesitate very substantial power rate increases within the next several years. Inflation continues, of course, to put upward pressure on all costs. The largest single factor in the need to increase power rates, however, is BPA's purchase of either all or a sizable portion of the



The proportioned and graceful architecture of BPA's 1200-kilovolt prototype reveals itself in structural details of conductors, insulators, and towers.

Source and Disposition of Revenue Dollar

Fiscal Year 1977
(In thousands)



Total Revenue	$223,592

Total Expenses	$237,003
Interest Paid From Prior Year's Surplus	(13,411)
Revenue Expended	$223,592

capacity of four nuclear plants. The first of these, the Trojan nuclear plant, of which BPA has purchased 30 percent of the capacity, is currently in operation and the costs thereof are reflected in BPA's current financial results. The financial impact of the remaining three plants, the Washington Public Power Supply System's Nuclear Projects Nos. 2, 1, and 3 (Plant No. 2 is being constructed first), will be impacting BPA's financial requirements over the next several years.

Cost Accounting and Repayment Reporting

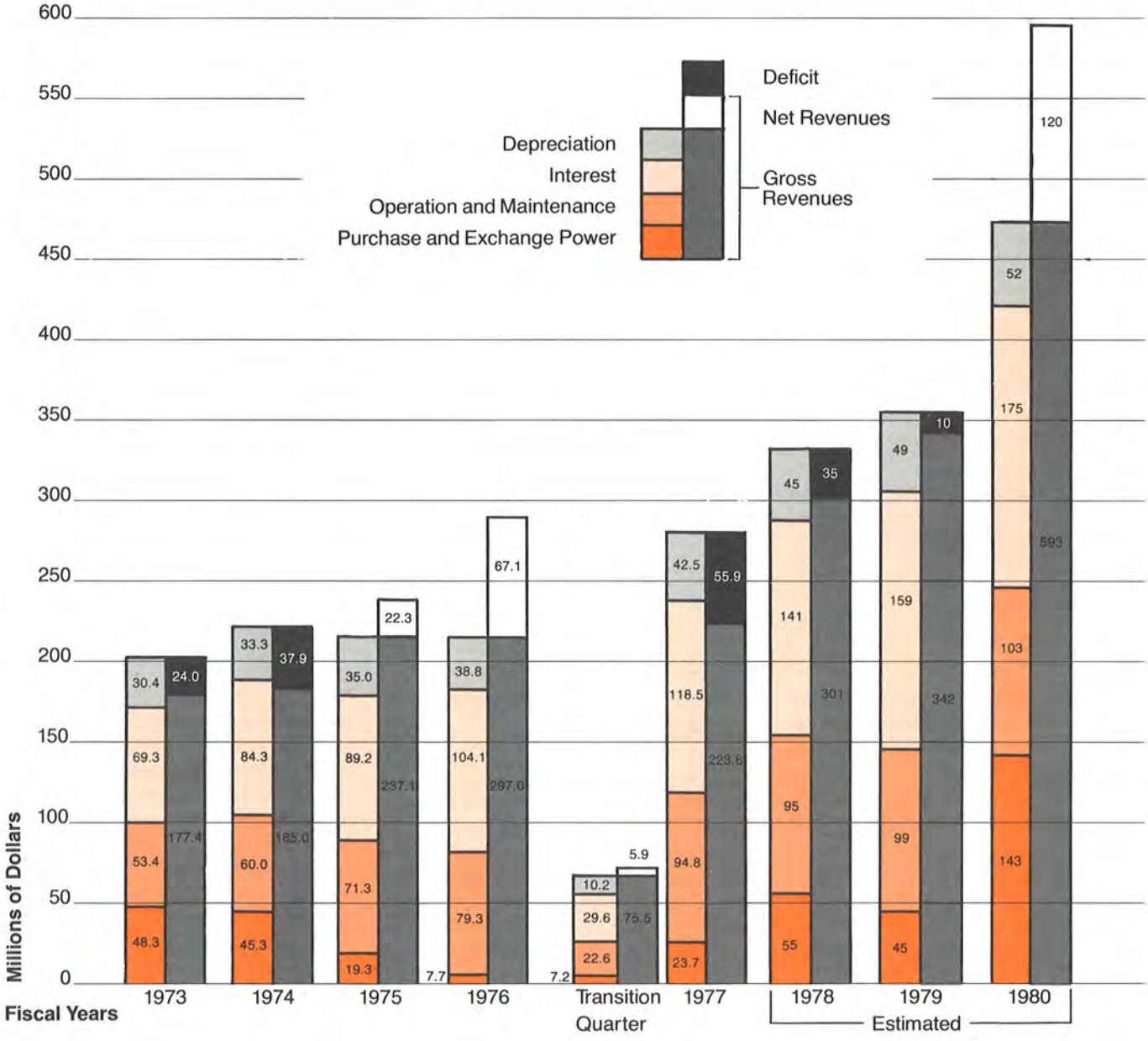
As noted above, this report includes both the cost accounting financial statements and the repayment study which constitutes the basis for determining revenue requirements. The cost accounting financial statements present financial results on an annual basis. The repayment study, on the other hand, consists of long-range forecasts of future revenues and expenses and the repayment of the investment in power facilities. The two sets of financial reports, therefore, seek to measure two different things, i.e., current financial results on the one hand and future financial requirements on the other.

The FY 1977 repayment study in summarized form is found on page 14 and 15 with an explanation of the repayment policy on page 16.

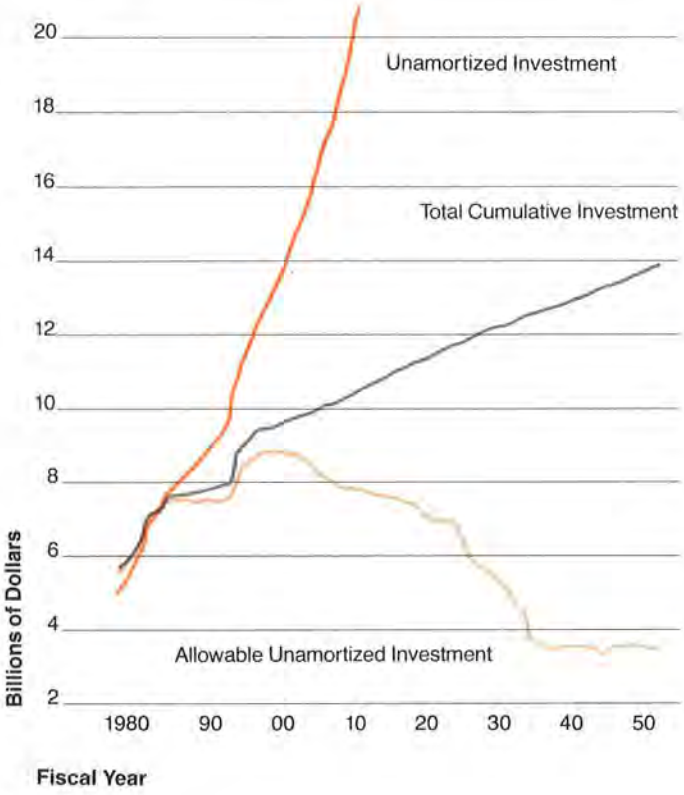
It should be noted that the cost accounting financial statements include depreciation of the power facilities over their expected useful lives which extend up to 100 years in some cases. The repayment policy, however, requires that the investment in such facilities be fully repaid within 50 years following each facility being placed in service. Consequently, the level of revenue required to meet the repayment requirements is higher than needed to cover costs on the cost accounting basis. Therefore, the normal situation with a rate level sufficient to meet the repayment requirements will be for the FCRPS to produce net revenues, i.e., operate "in the black." With the power rate level now in effect, which was previously approved by the Federal Power Commission through December 19, 1979, the prospects are for deficits during both FY 1978 and FY 1979. This prospect is illustrated graphically by the chart on page 7.

Another noteworthy difference between the cost accounting statements and the repayment study is that the latter reflects costs, such as purchased power, on a cash payment basis. The cost accounting statements, on the other hand, record such costs on the accrual basis. This results in different amounts being shown in the two sets of reports in some cases for the same item. This is especially true of purchased power expense where the contracts under which BPA is purchasing the capacity of the nuclear plants commit BPA to pay for such capacity beginning on specified dates even though the plants may not have commenced operation. For example, BPA's payment for its 100 percent share of the capacity of the WPPSS Nuclear Project No. 2 commenced in January 1977 even though the plant, due to construction delays, is not expected to be in operation until 1980. In this situation, the repayment study shows the amount of cash payments but the cost accounting statements defer charging such amounts to purchased power expense until the plant starts operating. This explains, for example, the different amounts shown for purchased power for the next several years in the repayment study (pages 14 and 15) and the forecast of the cost accounting results (page 7).

Revenue and Expense Trend



Repayment Study Chart
Fiscal Year 1977



Infrared photos obtained on night flights over the Seattle, Washington, and the McMinnville, Oregon, areas show hot (light) and cool (dark) areas. Heat from a factory produced two irregular white areas in photo above, and heat escaping through glass walls is apparently responsible for white areas surrounding Sea-Tac Airport (next page, upper left) and King Dome Stadium (lower right). Infrared records of subdivision (other two photos), with proper interpretation, can indicate possible need for weatherization of homes.

The FY 1977 repayment study included in this report shows that the revenues that can be expected from the current power rates will be inadequate to meet all repayment requirements. This is illustrated graphically by the repayment study chart appearing on this page. This repayment study, however, does not indicate the full extent of the future need to raise power rates because it includes only the costs of the nuclear plants (Trojan and WPPSS No. 2) currently being paid by BPA. The costs of the WPPSS Projects Nos. 1 and 3, payment for which must start in January 1980 and January 1981, respectively, must be included in the repayment studies to determine likely future rate increases.

December 1979 Power Rate Increase

Under the terms of BPA's power sales contracts, the earliest date that power rates can be increased is December 20, 1979. Futhermore, the contracts contained a provision limiting rate adjustments to only one each 5 years. Hence, under these contracts, assuming that BPA obtained approval of the necessary rate increase as of December 1979, the rates could not be increased again until December 1984.

Preliminary repayment studies developed for the 1979 rate adjustment, which include the costs of WPPSS Projects Nos. 1 and 3, have indicated that revenues would have to be increased at least 120 to 140 percent for the 5-year period December 1979 through December 1984. Even such a large increase, however, would not provide sufficient revenue if cost escalation were to continue at the rate experienced in recent years. The WPPSS nuclear plants, for example, have experienced both construction slippages and increasing costs each year. Because they will not be completed until between 1980 and 1983, there appears to be definite potential for further escalation. It was concluded, therefore, that to continue with the 5-year restriction on rate increases would pose serious problems. As a consequence, the Administrator proposed contract amendments to permit annual rate adjustments, if necessary, as of each July 1 commencing in 1981. At the time this report was prepared most customers had accepted the amendment, and it was expected that all would sign it. For planning purposes, therefore, it is now assumed that the December 20, 1979, rate increase will be followed by a second increase as of July 1, 1981.

On this basis, the preliminary repayment studies run to date indicate a need for approximately a 90 percent revenue increase in 1979 with an additional 20 percent increase in 1981.

It must be emphasized, however, that these results are preliminary and that the final power rate proposal to be formulated in 1979 may vary depending upon the conditions and cost estimates current as of that time.

Future Rate Approval Under Department of Energy

Creation of the new Department of Energy included the replacement of the Federal Power Commission, which formerly was responsible for approving BPA's power and wheeling rates. Two new regulatory entities were established within DOE. These are the Federal Energy Regulatory Commission and the Economic Regulatory Administration. The Secretary of Energy has delegated the authority for approving BPA's rates to ERA.

Progress on Wheeling Rates

In July 1976 BPA filed an application for increased wheeling rates with the now-defunct Federal Power Commission. FPC approval of the wheeling rates, which previously were approved by the BPA Administrator, is required under the 1974 Federal Columbia River Transmission System Act. The wheeling customers intervened in the FPC proceeding, complaining that the BPA rate proposal was excessive. The FPC approved the proposed rates, which increase wheeling revenues by some 22 percent, for a one-year interim period from July 1977 through June 1978. The FPC order granting the interim approval required an evidentiary hearing before an administrative law judge to determine the propriety of the rates and their compliance with the requirements of the Federal Columbia River Transmission System Act. Among other things, the Act requires that the recovery of the costs of the BPA transmission system be allocated fairly between Federal and non-Federal utilization of the transmission system.

At a prehearing conference in July 1977, BPA proposed a continuance of the hearing to permit time to develop a fully allocated cost-of-service study for the Federal system which would allocate transmission costs between the power and the wheeling customers. The intervenors agreed to the continuance and the administrative law judge set March 14, 1978, as the date for starting the hearing. At the time this report was prepared, BPA was in the process of completing the cost-of-service study, and its results were not yet determined. Final disposition of the case is now pending before the Economic Regulatory Administration.

Table 1

Electric Energy Account

Fiscal Year 1977

Energy Received (millions of kilowatt-hours)	
Energy Generated for BPA:	
Bureau of Reclamation	18,792
Corps of Engineers	43,965
Hanford Steamplant (NPR)	4,138
Centralia Thermal Project	2,681
Trojan Nuclear Plant	1,771
Other Generation	55
Power Interchanged In	54,128
Total Received	125,530
Energy Delivered (millions of kilowatt hours)	
Sales	61,746
Power Interchanged Out	59,934
Used by Administration	67
Total Delivered	121,747
Energy Losses in Transmission	3,783
Total	125,530
Losses as Percent of Total Received	3.0
Maximum Demand	13,675,000
(Date & Time) January 7, 1977, 9 am	
Load Factor	59.6

Table 2

Generation by the Principal Electric Utility Systems of the Pacific Northwest[1]

Fiscal Year 1977

Utility	Kilowatt-Hours (Billions)	Of Total Generation (Percent)
Publicly Owned:		
Federal Columbia River Power System[2]	71.4[3]	51.8
Grant County PUD	9.2	6.7
Chelan County PUD	6.7	4.9
Seattle City Light	4.4	3.2
Douglas County PUD	3.5	2.5
Tacoma City Light	1.5	1.1
Eugene Water & Electric Board	0.6	0.4
Pend Oreille County PUD	0.3	0.2
Total Publicly Owned	97.6	70.8
Privately Owned:		
Idaho Power Company	9.9	7.2
Pacific Power & Light Co.	12.6	9.1
Montana Power Company	6.4	4.7
Washington Water Power Co.	3.4	2.5
Portland General Electric Co.	6.1	4.4
Puget Sound Power & Light Co.	1.8	1.3
Total Privately Owned	40.2	29.2
Total Generation	137.8	100.0

[1] Generation shown is for members of the Northwest Power Pool plus Pend Oreille County PUD and Washington Public Power Supply System. Utah Power & Light Co., British Columbia Hydro and Power Authority and West Kootenay Power and Light, who are members of the Power Pool, are not included because their service area lies outside the Pacific Northwest.

[2] Includes generation from the Federal shares of each of the Washington Public Power Supply System's Hanford steamplant (NPR), the Centralia steamplant, and the Trojan Nuclear Plant.

[3] In addition to energy sales, includes PNW Coordination Agreement transactions, USBR energy reserved for irrigation pumping, Canadian Storage Power Exchange energy, and transmission losses.

General Specifications, Projects Existing, Under Construction and Authorized

Nameplate Rating of Installations as of December 31, 1977

					Existing		Under Construction		Authorized		Other Potential		Total	
Project	Operating Agency[1]	Location	Stream	Initial Date in Service	Number of Units	Total Capability Kilowatts	Number of Units	Total Capability Kilowatts	Number of Units	Total Capability Kilowatts	Number of Units	Total Capability Kilowatts	Number of Units	Total Capability Kilowatts
Bonneville	Ce	Ore-Wash.	Columbia	Jun. 1938	10	518,400	8-2	558,000[6]	—	—	—	—	18-2	1,076,400
Grand Coulee	BR	Washington	Columbia	Sep. 1941	21-3	4,063,000[2]	3	2,100,000[3]	—	—	6	4,200,000	30-3	10,363,000
Grand Coulee (Pump Generator)		Washington	Columbia-Banks Lake	Dec. 1974	2	100,000	4	200,000	—	—	—	—	6	300,000
Hungry Horse	BR	Montana	S. Fk. Flathead	Oct. 1952	4	285,000	—	—	—	—	—	—	4	285,000
Detroit	CE	Oregon	North Santiam	Jul. 1953	2	100,000	—	—	—	—	—	—	2	100,000
McNary	CE	Ore-Wash.	Columbia	Nov. 1953	14	980,000	—	—	10	1,050,000	—	—	24	2,030,000
Big Cliff	CE	Oregon	North Santiam	Jun. 1954	1	18,000	—	—	—	—	—	—	1	18,000
Lookout Point	CE	Oregon	M. Fk. Willamette	Dec. 1954	3	120,000	—	—	—	—	—	—	3	120,000
Albeni Falls	CE	Idaho	Pend Oreille	Mar. 1955	3	42,600	—	—	—	—	—	—	3	42,600
Dexter	CE	Oregon	M. Fk. Willamette	May 1955	1	15,000	—	—	—	—	—	—	1	15,000
Chief Joseph	CE	Washington	Columbia	Aug. 1955	19	1,309,000	8	760,000	—	—	13	1,573,000	40	3,642,000
Chandler	BR	Washington	Yakima	Feb. 1956	2	12,000	—	—	—	—	—	—	2	12,000
The Dalles	CE	Ore-Wash.	Columbia	May 1957	22-2	1,807,000[4]	—	—	—	—	—	—	22-2	1,807,000
Roza	BR	Washington	Yakima	Aug. 1958	1	11,250	—	—	—	—	—	—	1	11,250
Ice Harbor	CE	Washington	Snake	Dec. 1961	6	602,880	—	—	—	—	—	—	6	602,880
Hills Creek	CE	Oregon	M. Fk. Willamette	May 1962	2	30,000	—	—	—	—	—	—	2	30,000
Minidoka	BR	Idaho	Snake	May 1909	7	13,400	—	—	—	—	—	—	7	13,400
Boise Diversion	BR	Idaho	Boise	May 1912	3	1,500	—	—	—	—	—	—	3	1,500
Black Canyon	BR	Idaho	Payette	Dec. 1925	2	8,000	—	—	—	—	—	—	2	8,000
Anderson Ranch	BR	Idaho	S. Fk. Boise	Dec. 1950	2	27,000	—	—	—	—	1	13,500	3	40,500
Palisades	BR	Idaho	Snake	Feb. 1957	4	118,750	—	—	—	—	2	135,000	6	253,750
Cougar	CE	Oregon	S. Fk. McKenzie	Feb. 1964	2	25,000	—	—	1	35,000	—	—	3	60,000
Green Peter	CE	Oregon	Middle Santiam	Jun. 1967	2	80,000	—	—	—	—	—	—	2	80,000
Foster	CE	Oregon	South Santiam	Aug. 1968	2	20,000	—	—	—	—	—	—	2	20,000
John Day	CE	Ore-Wash.	Columbia	Jul. 1968	16	2,160,000	—	—	4	540,000	—	—	20	2,700,000
Lower Monumental	CE	Washington	Snake	May 1969	3	405,000	3	405,000	—	—	—	—	6	810,000
Little Goose	CE	Washington	Snake	May 1970	3	405,000	3	405,000	—	—	—	—	6	810,000
Dworshak	CE	Idaho	N. Fk. Clearwater	Sep. 1974	3	400,000	—	—	3	660,000	—	—	6	1,060,000
Lower Granite	CE	Washington	Snake	Apr. 1975	3	405,000	3	405,000	—	—	—	—	6	810,000
Libby	CE	Montana	Kootenai	Aug. 1975	4	420,000	4	420,000	—	—	—	—	8	840,000
Teton[5]	BR	Idaho	Teton		—	—	—	—	3	30,000[5]	—	—	3	30,000
Lost Creek	CE	Oregon	Rogue		2	49,000	—	—	—	—	—	—	2	49,000
Libby Reregulating	CE	Montana	Kootenai		—	—	3	76,400	—	—	—	—	3	76,400
Strube	CE	Oregon	S. Fk. McKenzie		—	—	—	—	1	4,500	—	—	1	4,500
Total Installed Capacity						14,551,780		5,329,400		2,319,500		5,921,500		28,122,180
Total Number of Projects						30		1		2		0		33

[1] CE — Corps of Engineers; BR — Bureau of Reclamation

[2] Includes three service units, an increase of 17,000 kW each for 17 rewound main units, and three 600,000kW units at the Third Powerplant.

[3] Three 700,000 kW units being installed at the Third Powerplant.

[4] Includes two fishway units of 13,500 kW each, 14 units of 78,000 kW each, and 8 units of 86,000 kW each at The Dalles Powerplant.

[5] Teton Dam ruptured June 5, 1976. Future status is unknown.

[6] Includes two fishway units of 13,000 kW each at the Bonneville Second Powerplant.

Sales of Electric Energy

Fiscal Year 1977

Customer	KWH (000)	Revenue
NORTHWEST AREA		
Publicly Owned Utilities		
Municipalities		
Albion, Idaho	2,889	$ 12,672
Bandon, Oregon	52,756	231,258
Blaine, Washington	35,858	149,116
Bonners Ferry, Idaho	31,021	142,782
Burley, Idaho	98,605	391,594
Canby, Oregon	77,626	340,129
Cascade Locks, Oregon	34,409	138,185
Centralia, Washington	94,485	441,507
Cheney, Washington	91,485	376,988
Consolidated Irrigation District, Washington	1,494	7,052
Coulee Dam, Washington	18,406	73,974
Declo, Idaho	2,392	11,094
Drain, Oregon	27,122	123,197
Eatonville, Washington	10,839	45,669
Ellensburg, Washington	143,290	579,476
Eugene, Oregon	1,480,588	4,992,208
Fircrest, Washington	42,068	180,236
Forest Grove, Oregon	115,481	464,002[1]
Heyburn, Idaho	74,621	282,388
Idaho Falls, Idaho	347,446	1,415,769
McCleary, Washington	31,760	139,739
McMinnville, Oregon	252,160	997,591[1]
Milton, Washington	21,407	88,724
Milton-Freewater, Oregon	98,694	402,064[1]
Minidoka, Idaho	1,004	4,194
Monmouth, Oregon	56,982	255,734
Port Angeles, Washington	562,956	2,137,315
Richland, Washington	436,456	1,814,018
Rupert, Idaho	59,604	251,089
Seattle, Washington	2,554,956	8,445,502[1]
Springfield, Oregon	653,980	2,501,849
Steilacoom, Washington	32,531	143,153
Sumas, Washington	6,082	25,327
Tacoma, Washington	2,115,113	7,187,780[1]
Vera Irrigation District, Washington	111,175	444,605
Wash. Public Power Supply System	26,592	98,607
Total Municipalities (36)	9,804,333	$ 35,336,587
PUBLIC UTILITY DISTRICTS		
Benton Co. PUD #1	1,031,762	$ 3,903,413
Central Lincoln PUD	990,545	3,737,191
Chelan Co. PUD #1	267,022	1,083,302[1]
Clallam Co. PUD #1	366,459	1,544,560
Clark Co. PUD #1	2,196,640	8,498,418
Clatskanie PUD	665,112	2,359,827
Cowlitz Co. PUD #1	2,636,734	8,823,245[1]
Douglas Co.PUD #1	324,386	1,111,676[1]
Ferry Co. PUD #1	50,966	207,804
Franklin Co. PUD #1	477,829	1,784,547
Grant Co. PUD #2	771,654	2,593,233[1]
Grays Harbor Co. PUD #1	1,120,853	4,105,063
Kittitas Co. PUD #1	23,773	98,672[1]
Klickitat Co. PUD #1	211,327	807,400
Lewis Co. PUD #1	578,320	2,266,441
Mason Co. PUD #1	47,622	203,931
Mason Co. PUD #3	323,343	1,304,938
Northern Wasco Co. PUD	201,810	852,471
Okanogan Co. PUD #1	393,629	1,537,785
Pacific Co. PUD #2	238,755	1,038,564
Pend Oreille Co. PUD #1	2,215	5,535
Skamania Co. PUD #1	86,739	358,514
Snohomish Co. PUD #1	3,895,543	14,676,071
Tillamook PUD	307,901	1,313,547
Wahkiakum Co. PUD #1	42,469	180,485
Whatcom Co. PUD #1	112,424	372,966
Total Public Utility Districts (26)	17,365,832	$ 64,769,599

Customer	KWH (000)	Revenue
Cooperatives		
Alder Mutual Light Co.	1,964	$ 8,495
Benton Rural Elec. Assn.	223,622	856,056
Big Bend Elec. Coop.	415,129	1,463,140
Blachly-Lane Co. Coop. Elec. Assn.	112,341	460,927
Central Elec. Coop.	208,937	830,835
Clearwater Power Co.	140,256	605,600
Columbia Basin Elec. Coop.	135,206	467,529
Columbia Power Coop. Assn.	36,498	136,159
Columbia Rural Electric Assoc.	167,579	614,296
Consumers Power	278,107	1,180,982
Coos-Curry Elec. Coop.	220,864	881,260
Douglas Elec. Coop.	128,066	544,718
East End Mutual Elec. Co. Ltd.	10,512	42,404
Elmhurst Mutual Power & Light Co.	126,537	534,005
Fall River Elec. Coop.	96,441	396,305
Farmers Elec. Co.	7,159	32,081
Flathead Elec. Coop.	92,627	351,741
Harney Elec. Coop.	141,146	448,821
Hood River Elec. Coop.	79,986	329,815
Idaho Co. Light & Power Coop. Assn.	32,941	134,156
Inland Power & Light Co.	356,350	1,434,788
Kootenai Elec. Coop., Inc.	130,195	519,706
Lakeview Light & Power Co., Inc.	174,754	715,137
Lane Co. Elec. Coop.	222,529	974,623
Lincoln Elec. Coop.—Mont.	45,319	183,139
Lincoln Elec. Coop.—Wash.	131,460	448,708
Lost River Elec. Coop.	57,702	186,457
Lower Valley Power & Light Co.	207,317	865,334
Midstate Elec. Coop.	124,276	470,892
Missoula Elec. Coop.	84,954	325,449
Nespelem Valley Elec. Coop.	37,511	152,830
Northern Lights	102,752	403,481
Ohop Mutual Light Co.	24,489	107,438
Okanogan Co. Elec. Coop.	23,906	94,914
Orcas Power & Light Co.	90,502	385,218
Parkland Light & Water Co.	92,499	390,186
Peninsula Light Co.	193,162	818,372
Prairie Power Coop.	9,092	34,871
Raft River Elec. Coop.	185,248	643,911
Ravalli Elec. Coop.	57,284	228,626
Riverside Elec. Co.	5,984	26,309
Rural Elec. Co.	61,331	250,304
Salem Elec.	191,473	761,315
Salmon River Elec. Coop.	34,616	115,239
South Side Elec. Lines	24,761	99,366
Surprise Valley Elec. Corp.	82,055	290,903
Tanner Elec.	17,656	83,877
Umatilla Elec. Coop. Assn.	630,657	2,138,475
Unity Light & Power Co.	40,684	169,015
Vigilante Elec. Coop.	74,643	274,562
Wasco Elec. Coop.	83,580	346,889
Wells Rural Elec. Co.	41,139	149,219
West Oregon Elec. Coop.	62,311	263,367
Total Cooperatives (53)	6,358,109	$ 24,672,245
Total Publicly Owned Utilities (115)	33,528,274	$124,778,431
Federal Agencies		
U.S. Energy Research Development Administration	327,061	$ 1,108,590
U.S. Bureau of Mines	7,191	38,309
U.S. Bureau of Reclamation-Roza Project	1,414	5,665
Fairchild Air Base	24,208	90,370
U.S. Bureau of Indian Affairs	119,126	443,067
U.S. Navy	221,300	877,449
Total Federal Agencies (6)	700,300	$ 2,563,450

Customer	KWH (000)	Revenue
Privately-Owned Utilities		
California-Pacific Utilities Co.	2,166	$ 7,581
Idaho Power Co.	0	0
Montana Power Co.	537,666	1,755,439[1]
Pacific Power & Light Co.	598,465	6,228,947[1]
Portland General Elec. Co.	521,176	3,646,681[1]
Puget Sound Power & Light Co.	816,459	4,984,822[1]
Utah Power Co.	165,957	653,682
Washington Water Power Co.	604,777	2,218,543[1]
Total Privately-Owned (8)	3,246,666	$ 19,495,695
Aluminum		
Aluminum Co. of America (combined)[3]	3,661,706	$ 9,842,259
Intalco Aluminum Co.	2,825,938	7,201,926
Kaiser Alum. & Chem. Corp (combined)[3]	4,863,903	12,733,313
Martin Marietta Aluminum Inc.		
Oregon	1,320,496	2,836,009
Washington	1,566,608	3,371,952
Reynolds Metals Co. (combined)[3]	5,134,648	13,236,995
The Anaconda Co. Aluminum Division	2,795,058	6,682,174
Total Aluminum (6)	22,168,357	$ 55,904,628
Other Industries		
Carborundum Co.	216,931	$ 569,005
Cominco American Inc.	0	0
Crown Zellerbach Corp.	85,602	235,069
Georgia Pacific Corp.	137,945	427,249
Hanna Nickel Smelting Co.	750,048	2,035,575
Oregon Metallurgical Corp.	27,356	127,685
Pacific Carbide & Alloys Co.	48,594	117,125
Pennwalt Corporation	326,228	854,674
Stauffer Chemical Works	433,973	1,345,551
Stewart Elsner	47	627
Union Carbide Corp.	75,705	185,654
Total Other Industries (11)	2,102,429	$ 5,898,214
Total Industries (17)	24,270,786	$ 61,802,842
Outside Northwest Region		
British Columbia Hydro & Power	0	$ 0
Burbank, California	0	−22,111[2]
Glendale, California	0	−53,725[2]
Los Angeles, California	0	−473,294[2]
Pasadena, California	0	−32,203[2]
Sacramento, California	0	0
Pacific Gas & Elec. Co.	0	3,824,093[1]
San Diego Gas & Electric Co.	0	−898[2]
Southern California Edison Co.	0	0
State of California	0	0
USBR-Mid-Pacific Region	0	735,000[1]
USBR-Lower Colorado Region	0	0
Total Outside Northwest Region (12)	0	$ 3,976,862
Total Sales of Electric Energy (158)	61,746,026	$212,617,280

[1]Includes capacity sales
[2]Financial transactions resulting from exchanges of capacity and energy
[3]See table below

	Pro rata	break by plant
Customer	MWH	Revenue
Aluminum Co. of America		
Addy	245,334	$ 659,431
Vancouver	1,523,270	4,094,380
Wenatchee	1,893,102	5,088,448
Kaiser Alum. & Chem. Corp.		
Spokane Reduction	3,146,945	8,238,454
Spokane Rolling	452,343	1,184,198
Tacoma Reduction	1,264,615	3,310,661
Reynolds Metals Co.		
Longview	3,147,539	8,114,278
Troutdale	1,987,109	5,122,717

BPA Cash Flow Forecast

(In Millions of Dollars)

Table 5

	FISCAL YEAR		
	1978	1979	1980
SOURCE OF FUNDS			
Revenues	301	342	593
Miscellaneous Receipts	1	1	1
Borrowing (Net)[1]	187	175	33
Total Received	489	518	627
APPLICATION OF FUNDS			
Net-billing	127	124	197
BPA O&M	55	67	68
BPA construction	118	115	116
Bond int. & amort.	6	17	25
Payments due Treasury	(183)	(205)	(221)
amount paid	183	195	221
amount deferred		(10)	
Total Payments	489	518	627
Cumulative Borrowing (Net)[1]	266	441	474
Borrowing Limitation[2]	317	441	568

[1]BPA borrowing from the U.S. Treasury includes the sale of long-term bonds as well as use of short-term cash advances to finance construction work in progress. Interest is payable on the net amount of the short-term advances actually used, with any unused cash remaining on deposit in the BPA Fund until needed or until repaid to the Treasury. To assure having sufficient cash to cover normal variations in the receipt and expenditure of cash, BPA ordinarily obtains a gross cash advance sufficient to cover forecasted expenditures plus a reserve. The amount of borrowing shown on this table is the net amount, i.e., the long-term bonds outstanding plus the amounts of the short-term advances expended.

[2]The borrowing limitation is the cumulative total of expenditures for construction, including capitalized interest during construction, since BPA went on the self-financing basis.

Repayment Study for Fiscal Year 1977

Authorized Projects *(All Amounts in $1,000)*

1	2	3	4	5	6	7	8	9	10	11
										PLANT ALLOCATED TO
					Investment Placed in Service			Cumulative Investment in Service		
Fiscal Year Ending Sept. 30	Revenues	Operation and Maintenance Expense	Purchase and Exchange Power	Interest Expense	Initial Project	Replace-ments	Total	Initial Project	Replace-ments	Total
Cumulative to 9-30-77	3,298,951	963,839	348,748	1,220,170	5,128,281		5,128,281	5,128,281		5,128,281
1978	301,000	94,849	119,746	141,019	551,021	12,497	563,518	5,679,302	12,497	5,691,799
1979	342,000	99,379	117,007	158,976	241,441	15,285	256,726	5,920,743	27,782	5,948,525
1980	354,000	103,622	134,074	174,975	231,000	50,974	281,974	6,151,743	78,756	6,230,499
1981	373,000	108,267	162,211	218,276	402,522	19,289	421,811	6,554,265	98,045	6,652,310
1982	392,000	112,388	173,248	247,161	544,539	28,852	573,391	7,098,804	126,897	7,225,701
1983	399,000	113,206	171,167	253,386		20,952	20,952	7,098,804	147,849	7,246,653
1984	406,000	115,178	162,735	273,937	329,212	25,383	354,595	7,428,016	173,232	7,601,248
1985	411,000	116,244	163,435	284,640	32,000	31,974	63,974	7,460,016	205,206	7,665,222
1986	417,000	116,586	164,035	291,668		26,335	26,335	7,460,016	231,541	7,691,557
1987	416,000	116,586	163,935	298,737		33,834	33,834	7,460,016	265,375	7,725,391
1988	411,000	116,586	162,935	308,905		31,220	31,220	7,460,016	296,595	7,756,611
1989	409,000	116,586	164,435	315,085		43,887	43,887	7,460,016	340,482	7,800,498
1990	408,000	116,586	162,335	324,506		57,226	57,226	7,460,016	397,708	7,857,724
1991	406,000	116,586	158,835	333,921		41,826	41,826	7,460,016	439,534	7,899,550
1992	405,000	116,586	158,835	346,093		79,272	79,272	7,460,016	518,806	7,978,822
1993	406,000	117,261	158,835	360,015	93,549	43,190	136,739	7,553,565	561,996	8,115,561
1994	413,000	119,611	158,835	401,959	732,141	71,116	803,257	8,285,706	633,112	8,918,818
1995	422,000	121,558	158,835	425,979	120,000	52,550	172,550	8,405,706	685,662	9,091,368
1996	424,000	123,559	158,835	454,711	184,468	82,832	267,300	8,590,174	768,494	9,358,668
1997	435,000	124,426	158,835	480,581	81,000	75,601	156,601	8,671,174	844,095	9,515,269
1998	438,000	125,292	158,835	502,431		54,741	54,741	8,671,174	898,836	9,570,010
1999	440,000	125,292	158,835	525,590		67,297	67,297	8,671,174	966,133	9,637,307
2000	442,000	125,292	158,835	550,463		65,775	65,775	8,671,174	1,031,908	9,703,082
2001	442,000	125,292	158,835	577,707		79,378	79,378	8,671,174	1,111,286	9,782,460
2002	442,000	125,292	158,835	606,966		81,276	81,276	8,671,174	1,192,562	9,863,736
2003	443,000	125,292	158,835	636,059		62,990	62,990	8,671,174	1,255,552	9,926,726
2004	444,000	125,292	158,835	668,220		71,028	71,028	8,671,174	1,326,580	9,997,754
2005	444,000	125,292	158,835	701,676		69,575	69,575	8,671,174	1,396,155	10,067,329
2006	444,000	125,292	158,835	738,906		86,300	86,300	8,671,174	1,482,455	10,153,629
2007	444,000	125,292	158,835	769,450		99,380	99,380	8,671,174	1,581,835	10,253,009
2008	443,000	125,292	158,835	800,652		73,907	73,907	8,671,174	1,655,742	10,326,916
2009	443,000	125,292	158,835	833,583		86,301	86,301	8,671,174	1,742,043	10,413,217
2010	442,000	125,292	158,835	908,294		117,147	117,147	8,671,174	1,859,190	10,530,364
2011	437,000	125,292	141,835	948,509		107,171	107,171	8,671,174	1,966,361	10,637,535
2012	436,000	125,292	124,835	989,471		97,925	97,925	8,671,174	2,064,286	10,735,460
2013	436,000	125,292	124,835	1,058,962		108,347	108,347	8,671,174	2,172,633	10,843,807
2014	436,000	125,292	124,835	1,107,500		84,618	84,618	8,671,174	2,257,251	10,928,425
2015	431,000	125,292	124,835	1,158,163		77,261	77,261	8,671,174	2,334,512	11,005,686
2016	415,000	125,292	6,300	1,238,787		109,238	109,238	8,671,174	2,443,750	11,114,924
2017	415,000	125,292	6,300	1,294,321		95,288	95,288	8,671,174	2,539,038	11,210,212
2018	415,000	125,292	6,300	1,352,060		99,488	99,488	8,671,174	2,638,526	11,309,700
2019	415,000	125,292	6,300	1,410,387		80,476	80,476	8,671,174	2,719,002	11,390,176
2020	415,000	125,292	6,300	1,573,237		107,058	107,058	8,671,174	2,826,060	11,497,234
2021	415,000	125,292	6,300	1,647,643		79,765	79,765	8,671,174	2,905,825	11,576,999
2022	415,000	125,292	6,300	1,725,953		104,093	104,093	8,671,174	3,009,918	11,681,092
2023	415,000	125,292	6,300	1,807,843		77,388	77,388	8,671,174	3,087,306	11,758,480
2024	415,000	125,292	6,300	1,893,055		78,964	78,964	8,671,174	3,166,270	11,837,444
2025	415,000	125,292	6,300	2,179,028		73,310	73,310	8,671,174	3,239,580	11,910,754
2026	415,000	125,292	6,300	2,295,032		101,495	101,495	8,671,174	3,341,075	12,012,249
2027	415,000	125,292	6,300	2,786,823		89,521	89,521	8,671,174	3,430,596	12,101,770
2028	415,000	125,292	6,300	2,961,372		74,627	74,627	8,671,174	3,505,223	12,176,397
2029	415,000	125,292	6,300	3,147,355		84,799	84,799	8,671,174	3,590,022	12,261,196
2030	415,000	125,292	6,300	3,595,380		67,264	67,264	8,671,174	3,657,286	12,328,460
2031	415,000	125,292	6,300	3,839,977		99,384	99,384	8,671,174	3,756,670	12,427,844
2032	415,000	125,292	6,300	4,103,589		91,915	91,915	8,671,174	3,848,585	12,519,759
2033	415,000	125,292	6,300	4,384,249		63,034	63,034	8,671,174	3,911,619	12,582,793
2034	415,000	125,292	6,300	4,684,665		66,345	66,345	8,671,174	3,977,964	12,649,138
2035	415,000	125,292	6,300	5,006,836		59,762	59,762	8,671,174	4,037,726	12,708,900
2036	415,000	125,292	6,300	5,353,372		79,633	79,633	8,671,174	4,117,359	12,788,533
2037	415,000	125,292	6,300	5,726,103		71,671	71,671	8,671,174	4,189,030	12,860,204
2038	415,000	125,292	6,300	6,124,459		57,951	57,951	8,671,174	4,246,981	12,918,155
2039	415,000	125,292	6,300	6,549,521		67,494	67,494	8,671,174	4,314,475	12,985,649
2040	415,000	125,292	6,300	7,006,915		77,975	77,975	8,671,174	4,392,450	13,063,624
2041	415,000	125,292	6,300	7,498,232		80,751	80,751	8,671,174	4,473,201	13,144,375
2042	415,000	125,292	6,300	8,027,338		102,371	102,371	8,671,174	4,575,572	13,246,746
2043	415,000	125,292	6,300	8,592,554		62,435	62,435	8,671,174	4,638,007	13,309,181
2044	415,000	125,292	6,300	9,200,328		69,839	69,839	8,671,174	4,707,846	13,379,020
2045	415,000	125,292	6,300	9,850,363		100,577	100,577	8,671,174	4,808,423	13,479,597
2046	415,000	125,292	6,300	10,545,870		84,695	84,695	8,671,174	4,893,118	13,564,292
2047	415,000	125,292	6,300	11,290,423		72,069	72,069	8,671,174	4,965,187	13,636,361
2048	415,000	125,292	6,300	12,088,996		97,181	97,181	8,671,174	5,062,368	13,733,542
2049	415,000	125,292	6,300	12,946,990		65,864	65,864	8,671,174	5,128,232	13,799,406
2050	415,000	125,292	6,300	13,966,481		69,851	69,851	8,671,174	5,198,083	13,869,257
Totals	33,700,951	9,889,965	6,408,421	208,992,839	8,671,174	5,198,083	13,869,257			

12	13	14	15	16	17	18	19	20	21	22
COMMERCIAL POWER					IRRIGATION ASSISTANCE					
		Allowable Unamortized Investment								
Amorti-zation	Unamortized Investment	Initial Project	Replace-ments	Total	Cumulative Amount in Service	Amorti-zation	Unamortized Amount	Allowable Unamortized Amount	Cumulative Surplus Revenues	Fiscal Year Ending Sept. 30
766,194	4,362,087	5,082,022		5,082,022	590,259		590,259	590,259		
54,614–	4,980,219	5,611,901	12,497	5,624,398	590,259		590,259	590,259		1978
33,362–	5,270,307	5,852,510	27,782	5,880,292	590,259		590,259	590,259		1979
58,671–	5,610,952	6,078,838	78,756	6,157,594	594,105		594,105	594,105		1980
115,754–	6,148,517	6,478,140	98,045	6,576,185	619,929		619,929	619,929		1981
140,797–	6,862,705	7,019,576	126,897	7,146,473	654,305		654,305	654,305		1982
138,759–	7,022,416	7,009,818	147,849	7,157,667	695,501		695,501	695,501		1983
145,850–	7,522,861	7,329,502	173,231	7,502,733	735,020		735,020	735,020		1984
153,319–	7,740,154	7,331,267	205,165	7,536,432	752,311		752,311	752,311		1985
155,289–	7,921,778	7,310,961	231,469	7,542,430	769,602		769,602	769,602		1986
163,258–	8,118,870	7,283,372	265,283	7,548,655	769,602		769,602	769,602		1987
177,426–	8,327,516	7,215,018	295,747	7,510,765	798,644		798,644	798,644		1988
187,106–	8,558,509	7,169,919	339,562	7,509,481	837,968		837,968	837,968		1989
195,427–	8,811,162	7,144,627	396,694	7,541,321	861,546		861,546	861,546		1990
203,342–	9,056,330	7,052,577	438,486	7,491,063	887,259		887,259	887,259		1991
216,514–	9,352,116	6,994,376	517,560	7,511,936	935,668		935,668	935,668		1992
230,111–	9,718,966	7,017,816	560,604	7,578,420	968,388		968,388	968,388		1993
267,405–	10,789,628	7,699,805	631,595	8,331,400	995,230		995,230	995,230		1994
284,372–	11,246,550	7,809,046	682,293	8,491,339	1,021,946		1,021,946	1,021,946		1995
313,105–	11,826,955	7,971,084	764,989	8,736,073	1,043,828		1,043,828	1,043,828		1996
343,456–	12,327,022	8,016,023	839,807	8,855,830	1,065,608	14,624	1,050,984	1,050,984		1997
348,558–	12,730,321	7,971,834	894,127	8,865,961	1,076,989		1,062,365	1,062,365		1998
369,717–	13,167,335	7,929,319	960,236	8,889,555	1,111,221		1,096,597	1,096,597		1999
392,590–	13,625,700	7,870,650	1,023,639	8,894,289	1,146,944		1,132,320	1,132,320		2000
430,036–	14,135,114	7,796,235	1,102,032	8,898,267	1,167,397	10,202	1,142,571	1,142,571		2001
449,093–	14,665,483	7,731,471	1,179,781	8,911,252	1,187,752		1,162,926	1,162,926		2002
477,186–	15,205,659	7,516,521	1,241,519	8,758,043	1,207,734		1,182,908	1,182,908		2003
509,128–	15,785,815	7,287,538	1,310,256	8,597,794	1,227,619	781	1,202,012	1,202,012		2004
541,803–	16,397,193	6,939,592	1,379,303	8,318,895	1,255,525		1,229,918	1,229,918		2005
579,033–	17,062,526	6,771,142	1,461,525	8,232,667	1,280,397		1,254,790	1,254,790		2006
609,577–	17,771,483	6,584,416	1,559,154	8,143,570	1,313,386		1,287,779	1,287,779		2007
644,730–	18,490,120	6,359,353	1,631,314	7,990,667	1,339,907	2,951	1,311,349	1,331,349		2008
680,995–	19,257,416	6,229,174	1,714,511	7,943,685	1,366,572	6,285	1,331,729	1,331,729		2009
750,421–	20,124,984	6,078,715	1,826,426	7,905,141	1,378,279		1,343,436	1,343,436		2010
778,636–	21,010,791	5,990,222	1,932,601	7,922,823	1,397,609		1,362,766	1,362,766		2011
804,101–	21,912,817	5,737,569	2,027,947	7,765,516	1,416,840	503	1,381,494	1,381,494		2012
910,611–	22,931,775	5,630,569	2,134,292	7,764,861	1,445,310	37,522	1,372,442	1,372,442		2013
962,757–	23,979,150	5,548,065	2,215,347	7,763,412	1,468,286	41,130	1,354,288	1,354,288		2014
1,021,799–	25,078,210	5,317,065	2,288,963	7,606,028	1,491,147	44,509	1,332,640	1,332,640		2015
1,019,342–	26,206,790	5,171,065	2,396,185	7,567,250	1,528,035	63,963	1,305,565	1,305,565		2016
1,064,903–	27,366,981	5,029,232	2,488,700	7,517,932	1,557,288	53,990	1,280,828	1,280,828		2017
1,088,922–	28,555,391	4,956,526	2,573,794	7,530,320	1,584,870	20,270	1,288,140	1,288,140		2018
1,186,804–	29,822,671	4,603,979	2,635,873	7,239,852	1,615,212	59,825	1,258,657	1,258,657		2019
1,315,930–	31,245,659	4,392,939	2,690,977	7,083,916	1,642,794	26,101	1,260,138	1,260,138		2020
1,382,814–	32,708,238	4,281,091	2,749,933	7,031,024	1,662,240	18,579	1,261,005	1,261,005		2021
1,459,828–	34,272,159	4,257,155	2,822,175	7,079,330	1,681,686	17,283	1,263,168	1,263,168		2022
1,530,561–	35,880,108	4,182,381	2,874,116	7,056,497	1,719,750	6,126	1,295,106	1,295,106		2023
1,626,994–	37,586,066	4,063,215	2,920,935	6,984,150	1,745,953	17,347	1,303,962	1,303,962		2024
1,903,958–	39,563,334	3,435,126	2,963,457	6,398,583	1,772,156	8,338	1,321,827	1,321,827		2025
2,030,825–	41,695,654	2,965,012	3,035,114	6.000.126	1,809,114	19,201	1,339,584	1,339,584		2026
2,523,470–	44,308,645	2,785,893	3,071,962	5,857,855	1,843,318	20,055	1,353,733	1,353,733		2027
2,695,921–	47,079,193	2,341,872	3,115,952	5,457,824	1,876,416	17,957	1,368,874	1,368,874		2028
2,876,901–	50,040,893	2,102,431	3,146,195	5,248,626	1,907,033	12,954	1,386,537	1,386,537		2029
3,314,306–	53,422,463	1,982,431	3,171,507	5,153,938	1,930,201	2,334	1,415,371	1,415,371		2030
3,565,523–	57,087,370	1,725,909	3,200,654	4,926,563	1,957,783	8,954	1,425,999	1,425,999		2031
3,820,181–	60,999,466	1,217,370	3,227,326	4,444,696	1,977,365		1,445,581	1,445,581		2032
4,107,811–	65,170,311	1,123,821	3,247,255	4,371,076	1,996,947	6,970	1,458,193	1,458,193		2033
4,411,444–	69,648,100	184,468	3,260,756	3,445,224	2,016,529	10,187	1,467,588	1,467,588		2034
4,743,582–	74,451,444	184,468	3,271,169	3,455,637	2,036,111	20,154	1,467,016	1,467,016		2035
5,101,053–	79,632,130		3,283,006	3,283,006	2,845,385	31,089	1,445,201	1,445,201		2036
5,467,718–	85,171,519		3,288,666	3,288,666	2,845,385	25,023	1,420,178	1,420,178		2037
5,841,051–	91,070,521		3,292,388	3,292,308	2,845,385		1,420,178	1,420,178		2038
6,280,111–	97,418,126		3,294,004	3,294,004	2,045,385	13,998	1,486,180	1,486,180		2039
6,744,522–	104,240,623		3,293,960	3,293,960	2,045,385	21,015	1,385,165	1,385,165		2040
7,257,436–	111,578,810		3,292,330	3,292,330	2,045,385	42,612	1,342,553	1,342,553		2041
7,767,256–	119,448,437		3,289,264	3,289,264	2,045,385	23,326	1,319,227	1,319,227		2042
8,375,279–	127,886,151		3,285,858	3,285,858	2,045,385	66,133	1,253,094	1,253,094		2043
8,943,483–	136,899,473		3,288,466	3,280,466	2,045,385	26,563	1,226,531	1,226,531		2044
9,566,955–	146,567,005		3,274,153	3,274,153	2,045,385		1,226,531	1,226,531		2045
10,262,462–	156,914,162		3,268,887	3,268,887	2,045,385		1,226,531	1,226,531		2046
11,007,015–	167,993,246		3,261,191	3,261,191	2,045,385		1,226,531	1,226,531		2047
11,834,630–	179,925,057		3,253,098	3,253,098	2,045,385	29,042	1,197,489	1,197,489		2048
12,702,906–	192,693,827		3,244,483	3,244,483	2,045,385	39,324	1,158,165	1,158,165		2049
13,606,651–	206,370,329		3,235,557	3,235,557	2,045,385	23,578	1,134,587	1,134,587		2050
192,501,072–						910,798				

Federal Columbia River Power System

Repayment Policy

Revenues must be sufficient to satisfy the following repayment criteria:

1. Pay the cost of operating and maintaining the power system.
2. Pay the cost of obtaining power through purchase and exchange agreements.
3. Pay interest on and amortize outstanding revenue bonds sold to the Treasury to finance transmission system construction.
4. Pay interest on the unamortized investment in power facilities financed with appropriated funds (Federal hydroelectric projects and BPA transmission facilities constructed prior to BPA's authorization to finance its construction program with sales receipts and revenue bonds).
5. Repay:
   a. Each increment of the power investment at the Federal hydroelectric projects within 50 years after such increment becomes revenue producing.
   b. Each annual increment of the investment in the BPA transmission system previously financed with appropriated funds within the average service life of the transmission facilities (changed from 40 to 35 years as of the start of FY 1978 based on new service life study).
   c. The investment in each replacement of a facility at a Federal hydroelectric project within its service life.

   (In repaying the investment financed with appropriated funds, the investment bearing the highest interest rate will be amortized first to the extent possible while still completing repayment of each increment of investment within its prescribed repayment period.)
6. Repay the portion of construction costs at Federal reclamation projects which is beyond the ability of the irrigation water users, and which is assigned for repayment from commercial power revenues, within the same overall period available to the water users for making their repayments. These periods range from 40 to 66 years, with 60 years being applicable to most of the irrigation repayment assistance.

A 200-foot tower at BPA's 1200-kilovolt transmission prototype near Lyons, Oregon, dwarfs technicians walking near line.

The FY 1977 Repayment Study (Table 6, pages 14 & 15), prepared in accordance with the foregoing criteria, shows that cumulative revenues through June 30, 1977, totaled $3.299 billion. These have been applied to pay purchase and exchange power costs of $349 million, operation and maintenance costs of $964 million, interest costs of $1.220 billion, with $766 million having been applied to amortization of the investment in power facilities. Cumulative power investment to be repaid from power revenues totaled $5.128 billion with the unamortized balance totaling $4.362 billion.

Starting with these cumulative results, the repayment study forecasts future revenues and costs over the balance of the repayment period. Costs and revenues are included for all Federal hydroelectric projects which are (1) currently in service, (2) under construction, and (3) authorized by Congress and scheduled for construction by the constructing agency, plus the costs of the transmission facilities necessary to market the output of these projects as well as handle the other sources of power transmitted by BPA. The repayment study also includes BPA power purchase costs for which payment is currently being made by BPA.

This repayment study shows that revenues are insufficient to meet all of the repayment criteria, i.e., the investment is not repaid within the permissible 50-year period.

Accountant's Report

COOPERS & LYBRAND
CERTIFIED PUBLIC ACCOUNTANTS

Administrator
Bonneville Power Administration
United States Department of Energy

We have examined the statement of assets and liabilities of the Federal Columbia River Power System (FCRPS) as of September 30, 1977 and 1976, and the related statements of revenues, expenses and accumulated net revenues and source and use of funds for the year ended September 30, 1977 and for the three-month period ended September 30, 1976. 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. The financial statements for the year ended June 30, 1976 were examined by the Comptroller General of the United States whose opinion, dated December 23, 1976, on the conformity of such financial statements with accounting principles and standards prescribed by the Comptroller General of the United States was qualified as being "subject to the financial effects of future adjustments related to the adoption of firm cost allocations and the effect of the financial decision on Teton Dam."

Recorded revenues are based upon rates for service established in accordance with the Bonneville Project Act and related legislation which are intended to provide for the full recovery of all FCRPS costs and repayment to the U.S. Treasury of its investment in power facilities and assigned irrigation costs within repayment periods established pursuant to such statutory requirements. As discussed in Note 1 to the financial statements, revenues needed to recover the costs of generating facilities are based on required repayment periods which are shorter than the periods over which such facilities are being depreciated, and the periods over which required net billed projects payments are recovered through revenues differ from the periods in which such payments are included in operating expenses. Under generally accepted accounting principles, revenues based upon cost recovery and the related costs should be included in the determination of net revenues in the same accounting period. Accordingly, the financial statements are not intended to present financial position and results of operations in conformity with generally accepted accounting principles. The financial statements are, however, appropriately presented in accordance with accounting principles required by or appropriate to applicable legislation and executive directives of other government agencies, as described in Note 1, and in accordance with accounting principles and standards prescribed by the Comptroller General of the United States.

As described in Note 3, certain utility plant cost and operation and maintenance expenses relating to multipurpose projects have been allocated on a tentative basis between power and nonpower purposes, and the amount of adjustments, if any, that may be necessary when allocations become firm is not determinable at this time.

In our opinion, subject to the effects, if any, on the financial statements of the ultimate resolution of the tentative cost allocations referred to above, such financial statements present fairly the assets and liabilities of the Federal Columbia River Power System at September 30, 1977 and 1976, and its revenues, expenses and accumulated net revenues and source and use of funds for the year and three-month period, respectively, then ended, in conformity with accounting principles described in Note 1 applied on a consistent basis for such periods and the preceding fiscal year.

Supplemental Schedule A showing the amount and allocation of plant investment as of September 30, 1977 was subjected to the audit procedures applied in the examination of the basic financial statements and in our opinion, subject to the effects, if any, on Schedule A of the ultimate resolution of the tentative cost allocations referred to above, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Portland, Oregon
December 16, 1977

Coopers & Lybrand

Federal Columbia River Power System

Statement of Revenues, Expenses and Accumulated Net Revenues

for the fiscal years ended September 30, 1977 and June 30, 1976 and for the three-month transition quarter ended September 30, 1976 (Note 1)

	Fiscal Year		Transition
	1977	1976	Quarter
	(Thousands of Dollars)		
OPERATING REVENUES:			
Sales of electric power:			
Publicly owned utilities	$125,292	$126,772	$ 25,429
Privately owned utilities	24,299	57,395	19,672
Federal agencies	3,530	7,975	2,263
Aluminum industry	37,401	70,927	19,791
Other industry	4,083	7,976	1,759
	194,605	271,045	68,914
Other operating revenues:			
Wheeling	19,060	17,531	4,210
Other	9,927	8,422	2,384
	28,987	25,953	6,594
Total operating revenues	223,592	296,998	75,508
OPERATING EXPENSES:			
Operation	55,772	48,775	13,439
Maintenance	39,019	30,516	9,171
Total operation and maintenance expense	94,791	79,291	22,610
Purchase and exchange power	23,719	7,692	7,176
Depreciation	42,495	38,785	10,156
Total operating expenses	161,005	125,768	39,942
Net operating revenues	62,587	171,230	35,566
INTEREST EXPENSE (INCOME):			
Interest on Federal investment (Note 7)	151,913	145,826	37,108
Allowance for funds used during construction	(28,373)	(35,561)	(6,712)
Interest income	(5,047)	(6,161)	(803)
Net interest expense	118,493	104,104	29,593
Net Revenues (Expense)	(55,906)	67,126	5,973
ACCUMULATED NET REVENUES:			
Balance at beginning of period	385,048	311,949	379,075
Balance at end of period	$329,142	$379,075	$385,048

The accompanying notes are an integral part of the financial statements.

Federal Columbia River Power System

Statement of Assets and Liabilities

at September 30, 1977 and 1976 and June 30, 1976 (Note 1)

ASSETS

	September 30, 1977	September 30, 1976	June 30, 1976
	(Thousands of Dollars)		
UTILITY PLANT (Notes 2 and 3):			
Completed plant (Schedule A)	$4,979,967	$4,593,744	$4,578,669
Accumulated depreciation	(392,603)	(354,321)	(347,547)
	4,587,364	4,239,423	4,231,122
Construction work in progress (Schedule A)	817,335	829,975	759,576
Net utility plant	5,404,699	5,069,398	4,990,698
CURRENT ASSETS:			
Unexpended funds (Note 4)	94,482	70,653	56,046
Investment in U.S. Government securities, at cost		34,208	27,257
Accounts receivable	6,674	9,166	23,008
Accrued unbilled revenues	11,843	37,041	36,923
Materials and supplies, at average cost	25,833	25,472	25,373
Total current assets	138,832	176,540	168,607
OTHER ASSETS AND DEFERRED CHARGES:			
Trust funds (Note 6)	13,386	9,016	10,454
Net billing advances, less amortization (Note 5)	97,449	35,490	38,039
Investment in Teton Dam (Note 9)	13,717	13,090	13,090
Other	10,359	13,553	12,569
Total other assets and deferred charges	134,911	71,149	74,152
	$5,678,442	$5,317,087	$5,233,457

LIABILITIES AND PROPRIETARY CAPITAL

PROPRIETARY CAPITAL:			
Investment of U.S. Government in power facilities:			
Congressional appropriations	$6,206,970	$5,918,480	$5,841,080
U.S. Treasury transfers to Continuing Fund	7,005	7,005	7,005
Transfers from other Federal agencies, net	41,338	39,539	39,489
Interest on Federal investment	1,622,472	1,470,559	1,433,451
Less funds returned to U.S. Treasury	(2,780,280)	(2,605,922)	(2,564,707)
Net investment of U.S. Government (Note 7)	5,097,505	4,829,661	4,756,318
Accumulated net revenues	329,142	385,048	379,075
Irrigation assistance (Schedule A and Note 8) $590 million, $544 million and $542 million, respectively			
Total proprietary capital	5,426,647	5,214,709	5,135,393
COMMITMENTS AND CONTINGENCIES: (Notes 2, 3, 5, 8, 9 and 10)			
CURRENT LIABILITIES:			
Short-term debt, U.S. Treasury (Note 2)	125,000		
Accounts payable	99,135	75,268	69,595
Employees accrued leave	7,544	7,064	7,362
Total current liabilities	231,679	82,332	76,957
DEFERRED CREDITS:			
Trust fund advances (Note 6)	13,386	9,016	10,454
Other	6,730	11,030	10,653
Total deferred credits	20,116	20,046	21,107
	$5,678,442	$5,317,087	$5,233,457

The accompanying notes are an integral part of the financial statements.

Federal Columbia River Power System

Statement of Source and Use of Funds

for the fiscal years ended September 30, 1977 and June 30, 1976 and for the three-month transition quarter ended September 30, 1976 (Note 1)

	Fiscal Year		Transition
	1977	1976	Quarter
	(Thousands of Dollars)		
SOURCE OF FUNDS:			
Operations:			
Net revenues (expense)	$(55,906)	$ 67,126	$ 5,973
Charges not requiring funds:			
Depreciation	42,495	38,785	10,156
Amortization of net billing advances	913	60	192
Funds provided from (used in) operations	(12,498)	105,971	16,321
Change in net investment of U.S. Government (Note 7)	267,844	259,009	73,343
Short-term borrowing from U.S. Treasury	125,000		
Decrease (increase) in current assets:			
Unexpended funds	(23,829)	73,752	(14,607)
Investment in U.S. Government securities	34,208	(18,932)	(6,951)
Receivables	27,690	(11,140)	13,724
Materials and supplies	(361)	(2,516)	(99)
Increase in current liabilities other than short-term borrowings	24,347	9,278	5,375
Total source of funds	$442,401	$415,422	$ 87,106
USE OF FUNDS:			
Investment in utility plant, net	$377,796	$377,617	$ 88,856
Increase (decrease) in net billing advances	62,872	16,991	(2,357)
Other, net	1,733	20,814	607
Total use of funds	$442,401	$415,422	$ 87,106

The accompanying notes are an integral part of the financial statements.

Notes to Financial Statements

Note 1. Basis of Preparation of Financial Statements and Summary of Significant 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 representing 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 the individual purposes through a cost allocation process. The portion of total project costs allocated to power is included in these statements as Utility Plant. Schedule A lists the projects included in FCRPS and the allocation of plant investment to the various purposes. Properties and income are exempt from taxation.

Accounts are kept in accordance with standards and principles prescribed by the Comptroller General of the United States and the uniform system of accounts prescribed for electric utilities by the Federal Power Commission (FPC). FCRPS accounting policies described herein also reflect requirements of specific legislation and executive directives issued by the involved government departments (BPA was a unit of the Department of Interior prior to its transfer to the Department of Energy effective October 1, 1977; the Bureau is a part of the Department of Interior and the Corps of the Department of Defense).

Revenues

Operating revenues are recorded on the basis of service rendered.

Rates established under requirements of the Bonneville Project Act and related legislation are intended to provide sufficient cash to meet all required payments for system costs (including operating expenses, repayment to the U.S. Treasury for its investment in power facilities and interest thereon, and costs of net billed projects) and assigned irrigation costs — see Notes 5, 7 and 8. The rates are also required to be low enough to encourage widespread use of electric energy at the lowest possible cost to consumers consistent with sound business principles.

Current policy requires that, except in unusual circumstances, operating expenses and interest be paid each year. There is no fixed annual requirement for payment of the power investment or assigned irrigation costs, the only requirement being that repayments be completed within prescribed periods. Payments to repay an investment bearing a higher rate of interest may be scheduled ahead of other investments bearing a lower rate to the extent that this is possible while still complying with prescribed repayment periods.

The rates make provision for recovery of the capital investment in transmission facilities within their average estimated useful service lives and within 50 years for power generating facilities. As set forth below, these assets are being depreciated in the accounts on a compound interest method over their estimated useful lives, which currently average approximately 40 years for transmission facilities and 85 years for generating facilities. Thus, annual depreciation charges are not matched with the recovery of the related capital costs and will, in the case of generating facilities, continue beyond the period within which such costs will have been recovered through revenues. Also, provision is currently being made in the rates for recovery of advances for net billed projects under construction, which amounts will not be charged to expense until the projects become operational.

Regulatory Authorities

BPA power and transmission rate schedules, formerly subject to confirmation and approval by the FPC, are currently subject to confirmation and approval by the Economic Regulatory Administration (ERA) of the U.S. Department of Energy which was created by Congressional action, effective as of October 1, 1977. ERA has not yet published regulations and procedures for handling federal power marketing rate matters.

Under terms of BPA's current power sales contracts, rates can only be adjusted at five year intervals. The present rates were approved by the FPC effective on December 20, 1974, and the earliest date on which these rates can be adjusted is December 20, 1979. Wheeling rates charged for transmission of nonfederal power were increased approximately 22% on July 1, 1977 under a temporary FPC rate order which expires June 30, 1978. These rate increases (which totaled approximately $750,000 at September 30, 1977) are subject to refund to customers in the event of regulatory disapproval.

Utility Plant and Depreciation

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, renewals and betterments is capitalized. Repairs and minor replacements are charged to operating expenses. With minor exceptions, the cost of utility plant retired, together with removal costs and less salvage, is charged to accumulated depreciation when it is removed from service.

Depreciation of utility plant is computed based on the estimated service lives of the various classes of property using the compound interest method (rates from 2½% to 3¼%). Service lives currently average approximately 40 years for transmission plant and 85 years for generating plant.

Depreciation provisions recorded in the accounts, expressed as a percent of the average cost of transmission and generating plant in service, approximated 1.9% and .4%, respectively, in each of the periods presented.

The compound interest method adopted pursuant to executive directives of government agencies results in increasing depreciation charges in the later years of service lives.

Allowance for Funds Used During Construction
The practice of capitalizing an allowance for funds used during construction is followed. Rates used are based upon interest rates stipulated for certain generating projects (2½% to 3¼%) and rates approximating the cost of borrowings from the U.S. Treasury for other construction (currently 6% to 7%).

Net Billing Advances and Amortization
Net billing agreements (see Note 5) provide that BPA make payments and/or grant billing credits prior to a nuclear project's date of commercial operation. Additionally, after the date of commercial operation amounts are payable by BPA (principally related to advances for future fuel purchases, plant additions and additions to debt service reserves) prior to the periods in which related economic benefits accrue. Such amounts are included as deferred charges under the caption "net billing advances" in the accompanying statement of assets and liabilities. These advances are amortized ratably over the project lives (approximately 35 years) or over lesser specific periods benefited and, together with other annual project costs, are included in purchase and exchange power expense.

Research and Development
Research and development costs, including depreciation of the cost of facilities constructed for research and development activities, are charged to expense. Costs charged to expense totaled approximately $2.9 million in 1977; charges to expense were not significant in 1976 and the transition quarter.

Retirement Benefits
Substantially all employees engaged in FCRPS activities participate in the Federal government's Civil Service Retirement Fund, a contributory pension plan. Retirement benefit expense is equivalent to 7% of eligible employee compensation.

Transition Quarter
Effective October 1, 1976 the Federal government's fiscal year was changed from the period July 1 through June 30 to the period October 1 through September 30. Accordingly, financial statements for the three-month "Transition Quarter" ended September 30, 1976 are presented herein.

Note 2. Financing of FCRPS Construction Program:

The Federal Columbia River Transmission System Act (Act), approved October 18, 1974, authorized BPA to use its operating receipts and proceeds from sales of revenue bonds, which the Act authorized it to issue, to finance further construction of the Federal transmission system in the Pacific Northwest. Prior to the enactment of this legislation, the transmission system construction program was financed through the appropriation process. During fiscal year 1976 BPA expended all unused portions of prior construction appropriations and commenced financing its construction program through use of its operating receipts and borrowing authority. Construction performed by the Corps and the Bureau continues to be financed through annual Congressional appropriations. In order to assist in financing the construction, acquisition and replacement of the transmission system, the Act authorized BPA to issue to the U.S. Treasury and have outstanding at any time up to $1.25 billion of bonds, notes or other evidences of indebtedness bearing interest and having terms and conditions comparable to those prevailing in the market for similar utility debt instruments. Under a note executed with the Treasury, BPA may borrow (within the aforementioned $1.25 billion authority) up to $250 million repayable within not more than three years from the beginning of the fiscal year in which borrowing occurs, at rates established by the Treasury. On September 30, 1977 BPA borrowed $125 million at 6.73%, repayable on or before September 30, 1978, to apply against approximately $195 million of construction costs previously financed from operating receipts. BPA has the option to convert the $125 million into long-term bonds having maturities and subject to such terms and conditions as may be prescribed by the Treasury.

BPA's construction budget for fiscal year 1978 is $118 million, for which substantial commitments have been incurred. Fiscal 1978 construction appropriations for power facilities have been authorized by Congress for the Corps and the Bureau totaling $197 million and $31 million, respectively.

Note 3. Tentative Cost Allocations:

Allocations of plant cost and operation and maintenance expenses between power and nonpower purposes for seven system projects are presently based on tentative allocations. At September 30, 1977, total joint plant costs for these seven projects approximated $2.3 billion of which $1.7 billion was tentatively allocated to power and subject to adjustment. In the past, adjustments have been made to plant cost and to accumulated net revenues (for adjustments relating to operation and maintenance, interest or depreciation) when firm allocations were adopted. The amount of adjustments that may be necessary when the allocations become firm is not determinable at this time.

Note 4. Unexpended Funds:

Unexpended funds consist of the unexpended balance of funds appropriated by Congress for construction, operation and maintenance purposes for the Corps and Bureau and cash balances of BPA. Amounts shown in the statement of assets and liabilities comprise:

	September 30,		June 30,
	1977	1976	1976
	(Thousands of Dollars)		
Corps and Bureau unexpended appropriated funds	$59,781	$65,719	$55,833
BPA cash balances	34,701	4,934	213
	$94,482	$70,653	$56,046

The Treasury credits FCRPS with interest on unexpended funds by deducting them from amounts on which interest payable to the Treasury is computed.

Note 5. Commitments to Exchange Power and Acquire Project Capability:

Existing net billing and exchange agreements provide that BPA will acquire all or part of the generating capability of the nuclear power plants listed in the table below. BPA is obligated to make payments, exchange power, or apply credits (net billings) to participating customers equal to the customers' portions of the annual project costs, including annual debt service requirements, whether or not the projects are completed, operable, or operated. The "Present Termination Commitment" represents the outstanding debt issued to finance the projects (without credit for salvage of assets or unspent construction funds) which would be payable over the varied financing repayment periods if the projects were terminated as of September 30, 1977:

			Estimated BPA Portion	
Project and % Capability Acquired	Projected in Service Date	Capacity in Megawatts	Present Termination Commitment	Additional Estimated Financing Requirements for Projects under Construction
			(Thousands of Dollars)	
WPPSS* Hanford Project (100%)	Operational	860	$ 54,200	
Net billed projects:				
Trojan Nuclear project (30%)	Operational	339	154,215	
WPPSS* Nuclear Project #1 (100%)	1982	1,250	535,000	$833,000
WPPSS* Nuclear Project #2 (100%)	1980	1,100	800,000	277,000
WPPSS* Nuclear Project #3 (70%)	1983	868	480,000	516,000

*Washington Public Power Supply System

BPA's commitment period under the net billing agreements extends for the life of the projects, except that the terms of the Trojan Nuclear Project net billing agreements under which Eugene Water & Electric Board (Eugene) assigned its 30% share of the project output to BPA and other participants, contain a provision allowing Eugene to withdraw the project capability for use in its own system beginning in 1984. Eugene has until July 1, 1978 (under an agreement granting a one-year extension from the original July 1, 1977 notification date) to give BPA notification of its intention to withdraw project capability. Eugene has notified BPA that, in the event the extension is determined to be invalid for any reason, it will withdraw substantially all of such capability in increments from 1984 through 1997. The net billing agreements provide for the repayment by Eugene to BPA of the net billing advances existing at the dates related capability is withdrawn. No such withdrawal options exist for the WPPSS projects. See Note 1 for information concerning net billing advances and amortization thereof.

BPA has also entered into agreement with a group of utilities to exchange an agreed amount of power for their rights to the Canadian Entitlement (one-half of the additional power benefits realized by downstream U.S. projects from three Canadian Treaty dams). The Canadian Entitlement was purchased for a 30-year period from the completion of each dam (the last dam was placed in service in 1973) by 41 Pacific Northwest utilities. BPA furnishes specified amounts of power to the utilities regardless of entitlement power generated. BPA's minimum average energy commitment to the utilities declines annually from approximately 700 megawatts currently to approximately 100 megawatts in the last year of the exchange agreement (2003).

Note 6. Trust Funds and Trust Fund Advances:

BPA receives funds from customers and others for the purchase of nonfederal power for customers' benefit and for construction to be done for others. The balance of trust funds and the related liability therefor at June 30, 1976 have both been reduced from amounts previously reported by $51,092,000 which had been expended for purchases of power for customers as of that date. Additionally, invested trust receipts of $6,980,000 previously included in investments in government securities at June 30, 1976 have been reclassified to trust funds.

Note 7. Net Investment of U.S. Government:

The Federal investment in each of the generating projects and for each year's investment in the transmission system is being repaid to the U.S. Treasury within 50 and 40 years, respectively, from the time the facility is placed in service. No such repayments are required during the next five years. However, amounts are to be paid annually for interest on outstanding Federal investment, net of interest capitalized on projects financed through appropriations, and for operating expenses. To the extent that funds are not available for payment, such amounts become payable from the subsequent year's revenue prior to any repayment of Federal investment. At September 30, 1977 all such required annual amounts were paid or accrued.

Interest rates applied to the unamortized Federal investment range from 2½% to 6⅛% (the weighted average rate was approximately 3.2% in 1977). The rates have been set either by law, by administrative order pursuant to law, or by administrative policies and have not necessarily been established to recover the interest costs to the U.S. Treasury to finance the investment. See Note 1 — Revenues and Note 8 for additional information concerning repayment requirements and policies.

Following is an analysis of changes in the Net Investment of U.S. Government:

	Fiscal Year Ended September 30, 1977	Three Months Ended September 30, 1976	Fiscal Year Ended June 30, 1976
	(Thousands of Dollars)		
Federal appropriations	$ 288,490	$ 77,400	$ 263,543
Transfers from other Federal agencies, net	1,799	50	1,493
Interest on Federal investment	151,913	37,108	145,826
Gross investment of U.S. Government	442,202	114,558	410,862
Funds returned to U.S. Treasury	(174,358)*	(41,215)	(151,853)
Change in net investment of U.S. Government	267,844	73,343	259,009
Balance, beginning of period	4,829,661	4,756,318	4,497,309
Balance, end of period	$5,097,505	$4,829,661	$4,756,318

*Includes $3.825 million accrued.

Note 8. Repayment Responsibility for Irrigation Costs:

Legislation requires that FCRPS net revenues will be used to repay to the U.S. Treasury that portion of the cost allocated to irrigation of any Pacific Northwest project authorized by Congress and determined by the Secretary, Department of Interior, to be beyond the ability of the irrigation water users to repay. The use of power revenues for such repayment represents a payment for irrigation assistance to the benefiting water users and, while paid by power rate payers, such costs do not represent a regular operations cost of the power program and are not included therein. The $590 million in irrigation assistance payments shown as payable from power revenues (detailed in Schedule A) will be reflected as reductions of accumulated net revenues at the time future payments are made. The first payment is scheduled to be made in 1997. The $590 million does not include any portion of $21 million of costs allocated to irrigation at six Corps projects where completion of irrigation facilities is not yet authorized. If completion is authorized, a determination of water users' repayment ability will probably be made which might result in additional irrigation assistance being payable from accumulated net power revenues.

Note 9. Teton Dam:

On June 5, 1976, before the project had been completed and turned over for the use of FCRPS, a breach occurred in the Teton Dam. The project was extensively damaged, and a vast amount of damage occurred downstream from the resulting flood. The total investment in the project at September 30, 1977 (excluding interest totaling approximately $521,000 subsequent to June 1976 which has been charged to expense) was $75.8 million. The amount of investment allocated to power was $13.7 million, and the amount of investment allocated to irrigation but repayable from power revenues was $44.8 million.

Disposition of the project's costs and final decision as to the repayment obligation are dependent upon Department of the Interior administrative action and/or Congressional action. If repayment is not required, the cost associated with the investment in power facilities will be charged off against the investment of the U.S. Government. Should FCRPS be directed to repay, 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 statement of assets and liabilities and the cost of applicable irrigation assistance is included in the total of other irrigation costs described in Note 8.

FCRPS will not be required to repay the costs of claims of non-federal entities and individuals resulting from failure of Teton Dam. The Congress enacted legislation to pay the costs of these claims and stipulated that all such payments would be nonreimbursable.

Note 10. Litigation:

The Confederated Tribes of the Colville Indians and the Spokane Indian Tribes (the Tribes) have asserted claims in unspecified amounts arising from construction of the Grand Coulee and Chief Joseph Dam projects. Without acknowledging liability on the part of the government, a committee of Congress has requested that the Departments of Interior and Army meet with the Tribes and attempt to resolve as many issues as possible. A major unresolved issue is the Tribes' assertion that they be permitted to share in power revenues from both projects. Negotiations are continuing and it is not possible at this time to determine the financial effect, if any, of the ultimate resolution of these claims on FCRPS. Should a negotiated settlement be reached, the settlement cost might be financed in whole or in part through Congressional appropriations.

On November 14, 1977, the City of Portland (the City) filed two lawsuits in the United States District Court for the District of Oregon against the Administrator of BPA and the Secretary of the Department of Energy. In the first suit the City alleges BPA has acted illegally in its sales of power to preference customers, private utilities and direct service industrial customers and that, as a result of such actions, the City has been denied an ability to purchase power from BPA. The City then requests that it be declared a preference customer; that BPA power sales agreements be set aside; that BPA adopt revised allocation procedures; and that BPA sell power to the City of Portland until such reallocation and revised rules are complete. The second suit is based upon BPA's alleged failure to comply with the terms of the National Environmental Policy Act. In this suit the City alleges that all BPA power sales contracts, extensions, renewals and the net billing agreements executed since January 1, 1970, were major Federal actions significantly affecting the quality of human environment in BPA's service area. The suit further alleges that BPA's actions have caused a serious impact on the City by reducing the quality of the environment. The City then asks that all power sales contracts, extensions, renewal agreements and net billing agreements entered into by BPA since January 1, 1970 be declared null and void; that BPA be required to prepare an environmental impact statement (EIS) on each of these agreements and that BPA be enjoined from executing any new power sales agreements or net billing agreements until BPA completes an EIS. In the opinion of the BPA General Counsel there is no substantial merit in either of the lawsuits and BPA intends to vigorously defend against these actions. The financial effects on FCRPS in the event of adverse decisions in these cases cannot be estimated.

A number of lawsuits are pending and threatened against the Corps and others for damages under alleged breaches of contract and for business losses incurred by individuals and business relocatees of the Town of North Bonneville in connection with construction of a second powerhouse at Bonneville Dam. The cost of disposing of these actions and resultant construction delays cannot be determined at this time.

Certain other claims, suits and complaints have been filed or are pending against entities of FCRPS. In the opinion of counsel and management, these actions are either without merit, involve amounts which are not significant to FCRPS' financial position or results of operations or, as in the case of the North Bonneville actions, primarily affect the overall cost of construction projects which will be capitalized and recovered through future power rates.

Note 11. Reclassifications:

For comparability, certain fiscal year 1976 amounts have been reclassified to conform with account classifications used in fiscal year 1977 and the transition quarter. There was no effect on previously reported net revenues.

Schedule of Amount and Allocation of Plant Investment

as of September 30, 1977

(Thousands of Dollars)

Project	Total	COMMERCIAL POWER: Completed Plant	COMMERCIAL POWER: Construction Work in Progress	COMMERCIAL POWER: Total Commercial Power	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	Percent of Total Returnable From Commercial Power Revenues
Projects in service:													
Transmission facilities (BPA)	$1,832,292	$1,677,541	$154,751	$1,832,292									100.0%
Albeni Falls (CE)	33,592	32,102	10	32,112				$ 134	$ 174		$ 1,172		95.6
Boise (BR)	69,514	5,238	1,380	6,618	$ 12,357	$ 35,428	$ 47,785		15,111				27.3
Bonneville (CE)	238,093	88,968	112,805	201,773				33,075			1,961	$ 1,284	84.7
Chief Joseph (CE)	341,923	217,798	123,021	340,819	728		728				255	121	99.9
Columbia Basin (BR)	1,257,673	408,723	298,034	706,757	435,105	68,092	503,197	1,000	46,193			526	90.8
Cougar (CE)	60,239	18,372	1	18,373		3,054	3,054	544	38,060			208	30.5
Detroit — Big Cliff (CE)	66,711	40,495	60	40,555		4,765	4,765	220	20,881			290	60.8
(a) Dworshak (CE)	321,365	282,726		282,726				10,706	20,750		7,183		88.0
Green Peter — Foster (CE)	89,819	49,642	8	49,650		5,777	5,777	363	30,112		1,856	2,061	55.3
Hills Creek (CE)	48,946	17,279	152	17,431		4,319	4,319	626	26,297			273	35.6
Hungry Horse (BR)	101,455	76,782	56	76,838					24,617				75.7
Ice Harbor (CE)	175,548	128,043	25	128,068				44,757			2,723		73.0
(a) John Day (CE)	523,189	382,967	4	382,971				87,829	14,774		11,206	26,409	73.2
(a) Libby (CE)	525,600	405,844	5,493	411,337					83,420		120	30,723	78.3
(a) Little Goose (CE)	219,636	120,111	45,786	165,897				47,088			4,047	2,604	75.5
Lookout Point — Dexter (CE)	95,748	45,734	167	45,901		1,336	1,336	715	47,191		511	94	47.9
(a) Lost Creek (CE)	138,959	27,211	(1,769)(e)	25,442		1,875	1,875		50,198	$23,116	25,083	13,245	18.3
(a) Lower Granite (CE)	365,249	250,475	45,638	296,113				53,759			7,887	7,490	81.1
(a) Lower Monumental (CE)	229,619	149,893	28,316	178,209				48,171			2,822	417	77.6
McNary (CE)	318,393	262,107	819	262,926				53,636			1,831		82.6
Minidoka — Palisades (BR)	129,821	13,411	135	13,546	10,196	43,513	53,709		62,092		178	296	18.3
The Dalles (CE)	320,998	273,875	2,443	276,318				42,593			2,065	22	86.1
Yakima (BR)	68,561	4,630		4,630	10,502	51,560	62,062		476	1,154	238	1	22.1
Irrigation assistance at 11 projects having no power generation	75,756				75,756		75,756						100.0
Plant investment	7,648,699	4,979,967	817,335	5,797,302	544,644	219,719	764,363	425,216	480,346	24,270	71,138	86,064	82.9
Repayment obligation retained by Columbia Basin Project	2,211	1,352		1,352(b)	859		859						100.0
(d) Investment in Teton Project	75,776		13,717	13,717	44,756	3,533	48,289		11,550		2,220		77.2
	$7,726,686	$4,981,319	$831,052	$5,812,371	$590,259	$223,252	$813,511	$425,216	$491,896	$24,270	$73,358	$86,064(c)	82.9%

BPA — Bonneville Power Administration
CE — Corps of Engineers
BR — Bureau of Reclamation

(a) Projects in service that have tentative cost allocations at September 30, 1977.

(b) Joint facilities transferred to Bureau of Sport Fisheries and Wildlife. This portion is included in other assets and deferred charges in the accompanying statement of assets and liabilities.

(c) Included in this amount are nonreimbursable road costs amounting to $75.8 million.

(d) Commercial power portion of Teton is included in other assets and deferred charges in the accompanying statement of assets and liabilities. Amounts exclude interest totaling approximately $521,000 subsequent to June 1976 which has been charged to expense.

(e) Negative amount results from estimated transfer to completed plant.

Reconciliation of Cost Accounting Financial Statements to Repayment Study

For The Transition Quarter Ended September 30, 1976
And the Fiscal Year Ended September 30, 1977
(All dollar amounts in thousands)
(unaudited)

	Cumulative Balance June 30, 1976	Transition Quarter and Fiscal Year 1977 Operations	Cumulative Balance Sept. 30, 1977	Cumulative Adjustment to Repayment Basis	Cumulative Data Through Sept. 30, 1977 on Repayment Study
OPERATING REVENUES	$2,999,851	$299,100	$3,298,951		$3,298,951
EXPENSES:					
Purchase and Exchange power	229,076	30,895	259,971	$ 88,777	348,748
Operation and maintenance expense	846,438	117,401	963,839		963,839
Interest expense	1,072,605	148,086	1,220,691	(521)	1,220,170
Depreciation	472,657	52,651	525,308	(525,308)	
Total expense	2,620,776	349,033	2,969,809	(437,052)	2,532,757
NET REVENUES	$ 379,075	$(49,933)	$ 329,142		
RECONCILIATION TO CUMULATIVE AMORTIZATION			$ 329,142	$437,052	$ 766,194(a)
PLANT INVESTMENT					
Completed plant			$4,979,967		
Retirement work in progress			35,339		
Repayment obligation retained by Columbia Basin Project (Schedule A)			1,352		
Repayment obligation for Teton Project (Schedule A)			13,717		
Net Retirements				$ 97,364	
Other				542	
			$5,030,375	$ 97,906	$5,128,281
Less amortization					766,194(a)
Unamortized plant investment					$4,362,087

(a) Changes in Cumulative Amortization:

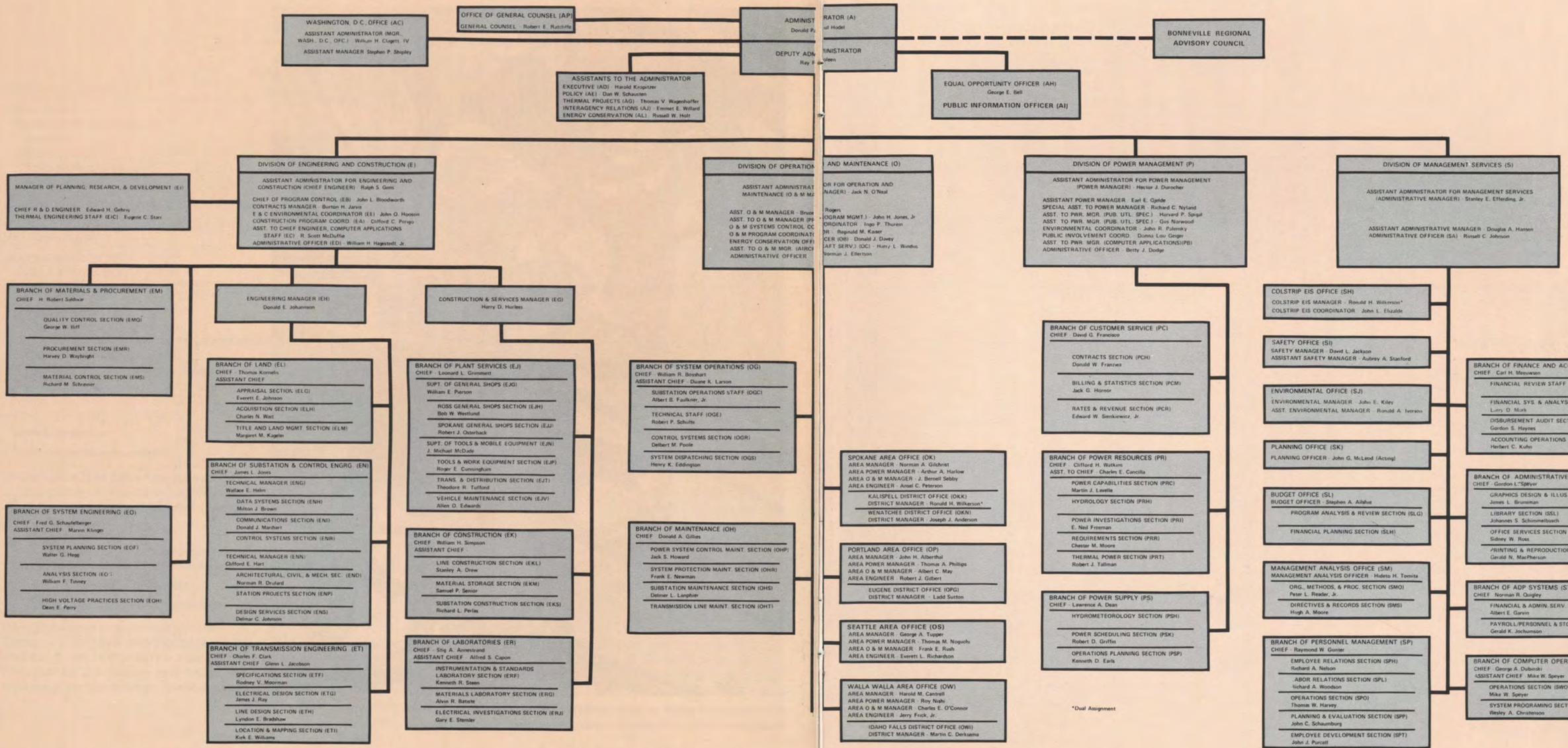
Cumulative amortization through June 30, 1976	$ 814,000
Fiscal Year 1977 and Transition Quarter:	
Depreciation	52,651
Net revenues	(49,933)
Purchase and exchange power-adjustment to cash basis	(51,045)
Interest adjustment for Teton Project	521
Amortization for the year	(47,806)(b)
Cumulative amortization through September 30, 1977	$ 766,194

(b) — Explanation of Negative Amortization
Through FY 1977 BPA amortized $188,536,000 of newly constructed transmission facilities by financing such construction from its temporarily available excess cash receipts in lieu of using its borrowing authority. Because of reduced cash flow during Fiscal Year 1977, BPA had to borrow funds from the U.S. Treasury as of the end of the year to recover a portion of the cash previously used to finance construction. This resulted in a reduction of the cumulative amount of amortization from use of cash receipts of $47,806,000.

Workman stands inside an eight-conductor bundle to check insulators on BPA's 1200-kilovolt installation.

BPA Organization Chart

December 1, 1977



2M June 1978 U.S. Department of Energy Portland, Oregon