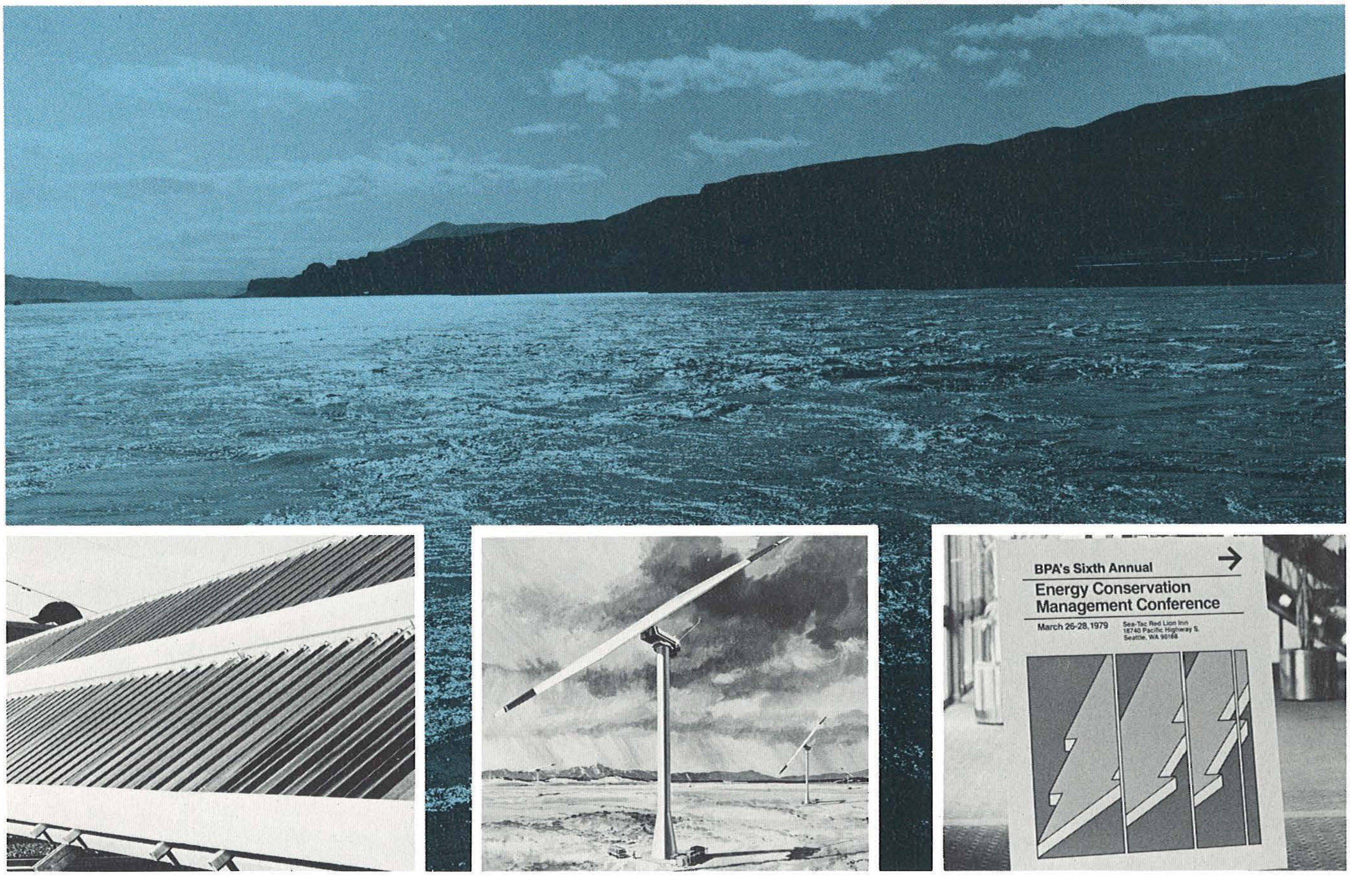
1979 ANNUAL REPORT
Bonneville Power Administration

U.S. Department of Energy




BPA is

Come Visit Us. . .

Lift the flap and see what we have to show you when you visit our headquarters building in Portland.

The headquarters exhibit shown in the large photo under the flap is one of two new exhibits we added in 1979. The other is located at our Ultra High Voltage (UHV) Test Facility on the outskirts of Lyons, Oregon. The small photos inside the flap are from the Lyons facility.

We also have exhibits at the Dittmer System Control Center at the Ross Complex in Vancouver, Washington, and at the Celilo Converter Station near The Dalles, Oregon.

During the coming year, we will develop an unmanned visitors' facility at the Goodnoe Hills windmill generating site near Goldendale, Washington.

Portland — At our headquarters exhibit, you will find computerized displays, photos, diagrams, games, and push-button slide shows and lighted maps with information about BPA and the region's power picture. Electric signs spell out daily bulletins on current BPA activities. A room off the lobby is being converted into a theater for slide shows and films, and will hold up to 15 persons. No appointments are necessary, but please feel free to call the BPA Information Office at (503) 234-3361, Ext. 5131 if you have any questions.

Lyons — This new Visitors' Center about 23 miles east of Salem via State Route 22 features films, slide shows, push-button quizzes and demonstration equipment to entertain visitors of all ages while informing them about the newest UHV technology for moving huge quantities of electricity over long distances with savings in line losses and right-of-way. Outdoor exhibits allow the visitor to inspect UHV hardware from close up, feel the presence of an electric field, and observe biological research involving cattle, honey bees, wildlife and plants. Visitors may just "drop in" or schedule visits for groups up to 30 persons by calling the BPA Information Office at (503) 234-3361, Ext. 5131. If you need directions after you reach the town of Lyons, call the center at (503) 859-2440.

Vancouver — The Dittmer visitors' program is designed especially for groups. It features a 3-image slide show in a theater that can hold 35 persons. It can include a guided tour of the Control Center that directs the flow of power from Canada to California and from the Pacific Ocean to The Continental Divide. Visits may be scheduled by calling the System Operations Officer at (206) 696-0351, Ext. 521.

The Dalles — The Celilo converter station, 2 miles south and east of The Dalles, is the northern end of the world's biggest and longest direct current line. The "drop in" visitors' center has displays explaining how alternating current is converted to direct current for power flow over the California Intertie. It also provides a peek into one of the rooms that houses the huge valves that convert the a-c to d-c. Guided tours can be scheduled through the Chief Operator at (503) 296-3615.

Goldendale — Since the Goodnoe Hills windmill site is only about 30 miles from Celilo, it will provide visitors with a two-for-one bonus. The Goodnoe Hills unmanned visitors' area will have displays to inform the public about the world's biggest-ever wind machines, three of which are being installed there for testing (see page 18). The Celilo visitors' center also will be expanded to tell the wind generator story.

So! Come visit us. Bring your friends. Tell others. We think you'll enjoy the visit, and learn something interesting.

1979 Annual Report

Federal Columbia River Power System

U.S. Department of Energy
Charles W. Duncan, Jr.
Secretary

Bonneville Power Administration
Sterling Munro
Administrator

On the cover, the mighty Columbia River, symbolizing the old, serves as a backdrop for inset photos illustrating some power sources of tomorrow. Insets, left to right, show solar collectors at BPA's Big Eddy Substation near The Dalles, Oregon; a model of the world's largest windmill, three of which are being installed by DOE on the BPA system near Goldendale, Washington; and a sign calling attention to BPA's Sixth Annual Energy Conservation Conference.

On opposite page, with photos of BPA's seven previous administrators on wall in the background, Administrator Sterling Munro (hand gesturing) confers with former Assistant Secretary of Energy George McIsaac. Insets, left to right, show Secretary of Energy Charles W. Duncan, Jr., Deputy Secretary John Sawhill, and McIsaac's successor, Assistant Secretary Ruth Davis, to whom BPA reports.

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LETTER TO THE SECRETARY

Honorable Charles W. Duncan, Jr.
Secretary of Energy
Washington, D.C. 20545

Dear Mr. Secretary:

In this 42nd Annual Report of the Bonneville Power Administration, we are pleased to be able to report specific actions to further the President's energy program, especially with respect to conservation and renewable resources.

We began in 1979 four important conservation pilot programs with several of the utilities which buy wholesale power from us and sell it at retail. We are optimistic about the prospects for the additional Congressional authorization necessary to enlarge our conservation efforts into full-scale regionwide programs.

BPA was selected by DOE to test a cluster of three big Boeing-built wind generators at Goodnoe Hills near Goldendale, Wash. Standing on 200-foot towers with 300-foot long blades, they will have 2.5 megawatts of capacity each and will be the largest windmills ever built anywhere in the world. The first is scheduled to be generating electricity for the Bonneville grid as early as December 1980, and all three by mid-1981.

Using both our own staff and contractors, we have launched a major assessment of the potential for all forms of alternatives and renewable resources in our region, including small-scale decentralized direct applications as well as central station uses.

In October, together with the four Pacific Northwest states, we co-sponsored the region's first Alternative and Renewable Resources Conference. It will become an annual fall event, just as our energy conservation conferences have become an annual spring event—last April we held our sixth.

The Pacific Northwest Electric Power Planning and Conservation Bill passed the Senate in August but at year's end was still pending in the House. It would authorize BPA to undertake much more responsibility in the areas of conservation and renewable resources along with more responsibility for helping plan and supply the region's electric needs. Also pending was an amendment to the DOE authorization bill proposing to authorize BPA to make expenditures from the Bonneville Fund for conservation and renewable resource activities.

We have drafted and circulated in the first stage of our public involvement process a proposed allocations policy which will determine how the available Federal supply will be rationed among preference customers after 1983 if we are unable to augment supplies by virtue of new legislation.

New regional power legislation could be as important to the region over the next 42 years as the original Bonneville Project Act has been over the past 42.

Sincerely yours,

Sterling Munro

Sterling Munro
Administrator

THE REGION'S POWER FUTURE

TV camerman records one of the many public involvement sessions characterizing BPA's activities as the people of the region grapple with the issues represented by the three inset photos: the regional power bill, allocations, and the Role EIS.

Where Do We Go From Here?

Last year's annual report began: "The region's power future, and BPA's role in it, are being shaped now."

The same words are as true today as they were a year ago.

But there has been much progress:

- A modified regional power bill has passed the United States Senate and at year's end was pending in the House of Representatives.
- The Revised Draft Role EIS—the bench-mark environmental impact statement concerning the region's future power picture and BPA's place in it—is now before the Department of Energy (DOE) for review and approval before filing with the Environmental Protection Agency (EPA).
- BPA's new wholesale power rates, for the period December 20, 1979 until July 1, 1981, are in effect on an interim basis by action of the DOE Assistant Secretary for Resource Applications, but still must be approved by the Federal Energy Regulatory Commission (FERC).
- We have developed and circulated for public comment a proposed allocations policy. It would, in effect, ration available Federal power among preference customers after 1983. We also have begun preparation of the environmental impact statement to accompany it, an EIS which is separate and distinct from the Role EIS.

The Regional Bill: Background

Is there a better way than the Senate-passed regional power bill to plan and meet the region's future power needs and hold down costs?

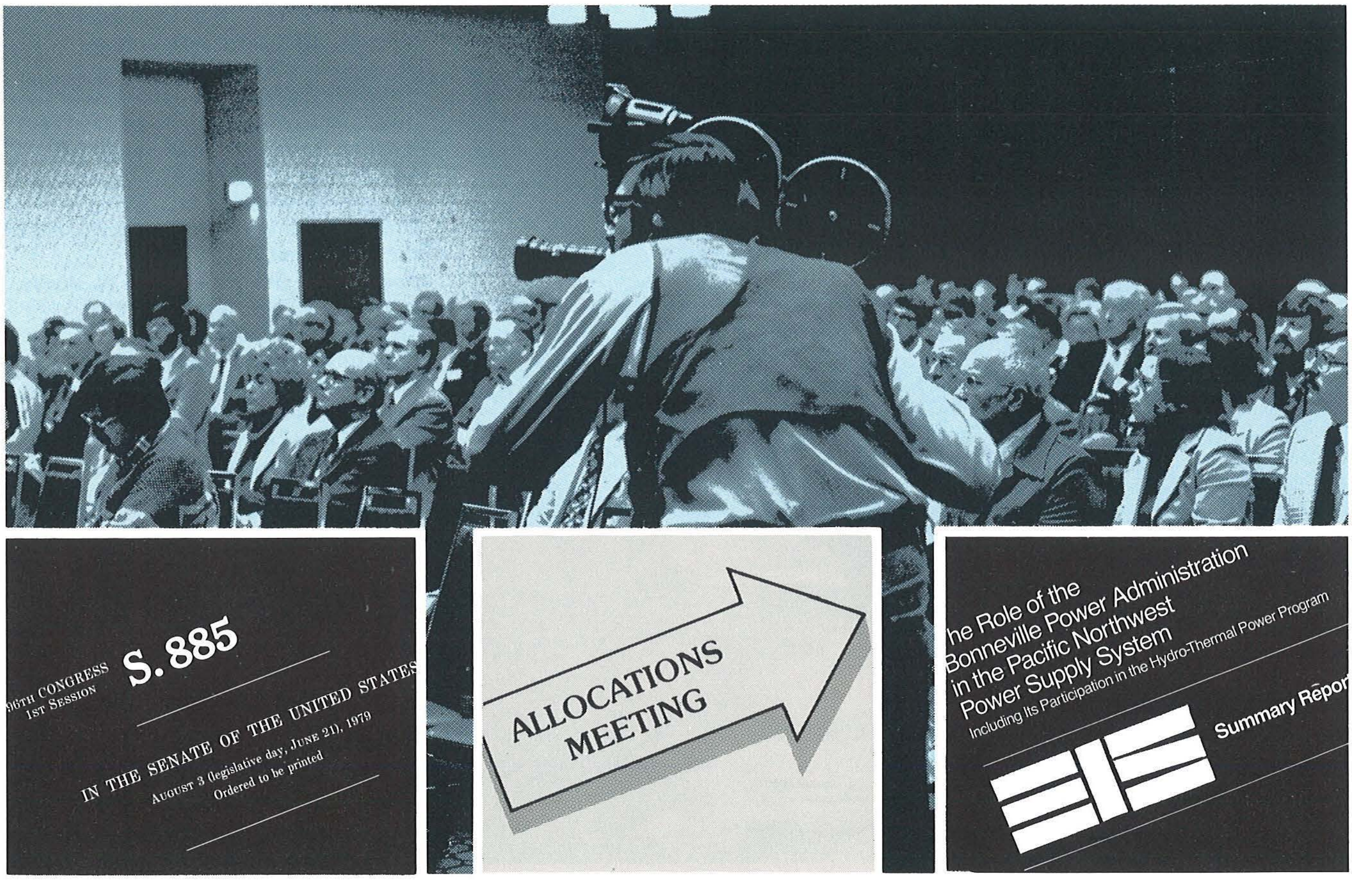
Because some in public power weren't certain from the start, and because others developed doubts during the extensive Congressional hearings in 1979, the Public Power Council (PPC) requested that the House delay any final action on the bill until 1980.

The PPC, representing 115 preference customers who buy part or all of their wholesale power from BPA, wanted time to study and decide whether its members would be better off under the bill or under the proposed BPA allocations policy. Just before Christmas the PPC announced several recommended amendments which they said would make the bill acceptable to them.

The proposed allocations policy, as discussed under a separate heading below, would ration available Federal power among the public bodies and co-ops which, under preference laws, have first call on available Federal power.

But both the short-term and long-term power supply situation, described more fully in the Power Operations section, look bad. And the cost of all forms of energy, including Pacific Northwest electric power rates, is climbing.

The problems appear to be more serious for investor-owned utilities than for municipals, PUDs and co-ops over the next 10 years. This is because the large Federal hydro base available for BPA preference customers has deferred their need for new thermal generation, and because delays in thermal power projects being built by the private utilities are even more serious than delays in those being built for public power. But this could change if



either of two likely events were to occur.

If people presently served by private power were to form new public bodies that qualified for a share of available Federal power, as the State of Oregon is now trying to do, smaller shares of power would be available for existing preference customers.

Further, public power's more favorable supply outlook through the '80s depends upon presently scheduled completion dates being met for two nuclear power plants being constructed for them by the Washington Public Power Supply System (WPPSS). These two plants are being built without BPA participation, as distinguished from the three WPPSS nuclear plants for which BPA will market the power and meld the higher power costs with low-cost Federal hydro. If WPPSS nuclear units 4 and 5 encounter the kinds of delays the first three have met, or even lesser delays, the supply outlook and the cost outlook for the region's preference customers will deteriorate.

The Regional Bill: Details

The regional power bill passed by the Senate is intended to bring supply and demand into balance rather than allocate a shortage. BPA would be authorized to invest in conservation and purchase power to meet our preference customers' full requirements after 1983, plus other loads.

The bill would require BPA to maximize conservation and place development of renewable resources ahead of non-renewables.

It would establish a formal process for assuring non-utility input into the region's power decisions.

The bill would enable BPA to sign new long-term contracts with the aluminum and other industrial loads we now serve directly. These industries would give up the remaining years of their present contracts for low-cost Federal power in exchange for new long-term contracts at higher rates reflecting the cost of new power supplies.

Availability of the power supplies relinquished by the industries would enable BPA to sell to the private utilities an amount of power equivalent to the needs of their residential and small farm customers, but only on receipt from them of an equivalent amount of power at their average system cost. The power sold to private utilities for this purpose would be at the same rates at which we sell to preference customers, and the cost differential would initially be paid by BPA's direct-service industrial customers. The benefits of Federal power would have to flow through directly to the consumers served by the private utilities, and not to the utilities themselves.

Preference customers would continue to receive first call on power from BPA, being protected both as to supply and price.

While BPA would not build new power projects, the bill would permit BPA, in effect, to place the equity of the Federal Columbia River Power System behind projects built by the region's utilities. This would also spread regionwide the dry-hole risks for new resources, including conservation and renewables should they fall short of expectations.

At left, environmental leaders and BPA officials talk over issues during meeting at BPA headquarters. Opposite page shows some public power leaders making points during meeting on the regional power bill. Left to right are Jack R. Criswell, General Manager of the Springfield Utility Board and a former president of the Northwest Public Power Association (NWPPA); Alan H. Jones, General Manager of the City of McMinnville Water & Light Department and Chairman of the Public Power Council (PPC); Joseph Recchi, Assistant Superintendent of Seattle City Light and a member of the NWPPA Board of Directors, and Ferris Gilkey, General Manager of the Grays Harbor PUD.

BPA, the Department of Energy and other agencies of the National Administration testified in favor of the Senate-passed bill with amendments.

Major concerns of the Administration were treated in Senate amendments clarifying (1) the reporting relationship of the Administrator to the Secretary of Energy, (2) the definition of cost-effectiveness as applied to conservation measures, (3) applicability of anti-trust laws to the regional power planning body the bill would create, and (4) the prohibition against BPA construction and ownership of any major electric generating facilities.

Other Administration amendments are before the House along with several that have been or will be offered by the PPC and others.

The Administration amendments being considered by the House relate to (1) the purposes for which BPA borrowings from the Treasury could be made, (2) Congressional approval of such borrowings, and (3) the method for determining interest rates on such borrowings.

The PPC amendments proposed in December reaffirm preference principles as to the price and supply of Federal power; emphasize local control and the authorities of state and local governments and preference utilities; preserve utility initiative to undertake independent conservation measures; clarify the extent to which utilities must use their own generating resources to serve their own loads, and clarify some technical points. The PPC still had under study at year's end a tentative amendment affecting the role and composition of the regional planning body.

Other amendments pending or anticipated would deal with administrative procedures, a variety of environmental and conservation concerns, and fish protection and propagation. No specific fish amendments were pending at year's end, but several were expected from Members of Congress. Remaining environmental concerns had not been expressed in specific amendments except by the Natural Resources Defense Council, some of whose amendments were addressed by the Senate.

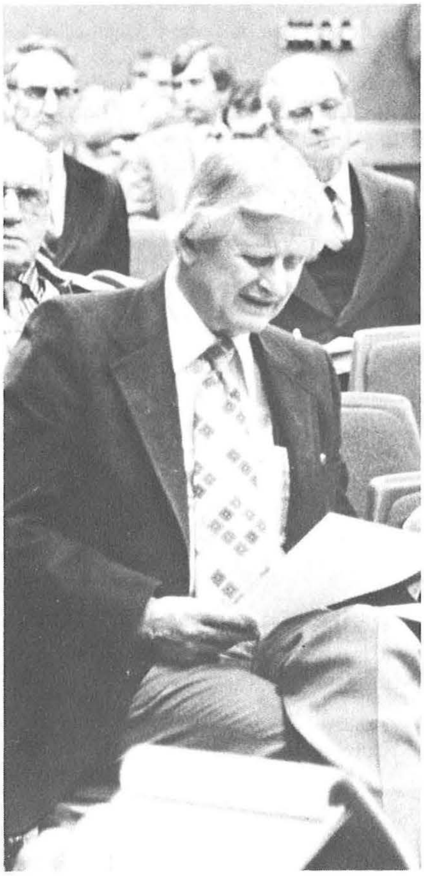
The Role EIS

A revised draft Role EIS is now before the DOE for review and filing with the EPA. The document sets forth alternatives that amount to a continuation of BPA's present role, a larger role, and a lesser role. Some of the alternatives reflect the kinds of functions and authorities contained in legislation now before Congress.

The public has been informed through the many public involvement forums we held to discuss and receive comments on the draft. An additional 30-day review period will be provided once the revised draft is filed.

The Role EIS has taken nearly five years to complete at a cost of $3 million. It has gone through several drafts in order to reflect changes in the regional energy picture and comments received through the public involvement process. It was shortened from its original 3200 page length to 400 pages.

The Role EIS covers the areas required by a court order and goes somewhat beyond. Our effort was to produce a bench mark document



that will set the stage for future EIS's relating to BPA involvement in specific resource issues.

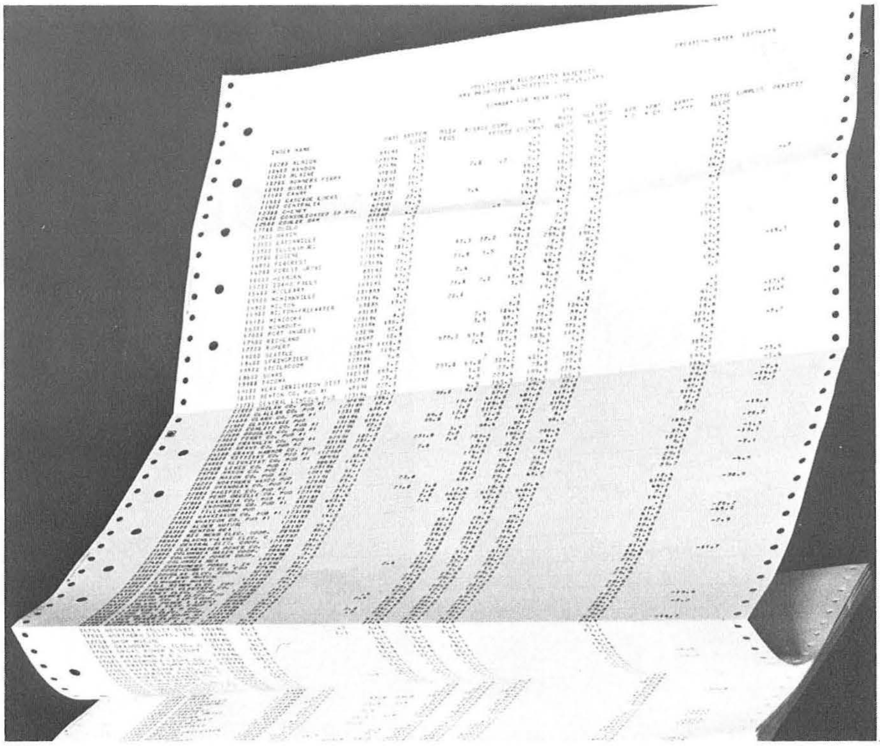
Proposed Allocations Policy

After 1983, BPA no longer will be able to supply the full energy requirements of preference customers unless the regional power bill or some other legislation makes that possible. In proposing an allocations policy to ration the available Federal energy after 1983, we have stressed conservation and protection of the smaller public bodies and co-ops.

To promote public interest and stimulate study of our proposed policy prior to the public ***comment*** forums to be held in 1980 — during which we will seek formal comments — we held seven public ***information*** forums at various locations in the region. One technical information forum was also held in Portland. Some 400 persons attended the eight meetings. In December, we also held a "scoping" meeting in Portland to identify significant issues that others propose be analyzed in depth in the EIS that will accompany our allocations policy; about 60 persons attended.

These are the major elements in our proposed allocations policy:

- Public bodies and cooperatives would get first call on available Federal energy, as provided by the Bonneville Project Act, with no exclusion of new public bodies and co-ops that may be established and qualify for preference.
- Existing preference customers would each receive a base allocation. While short of meeting the full requirements of the larger customers, this would provide them with a guaranteed amount of energy until 1991.
- The 66 small customers who use less than 25 average megawatts would be entitled to receive their full requirements — up to that amount — through July 1, 1991. But to receive this treatment, they like all preference customers would be required to adopt suitable conservation programs.
- Prior to 1991, new BPA preference customers would in the first year of service be given a base allocation from the energy made available by the expiration of contracts with BPA's industrial and Federal agency customers. After the first year, they would share in additional energy available for allocation the same as existing preference customers.
- After July 1, 1991, there would be no distinction between existing and new preference customers, or large and small preference customers. All would receive an equal percentage share of their net needs from the available Federal supply.
- During the transition period, inasmuch as some customers will receive a greater share of their net requirements from Bonneville than others — and since those customers would not need to buy as many resources to meet the balance of their own loads — they would be required to share in the cost of new resources acquired by the customers who have to buy a greater share. This sharing would not make costs equal, but it does mean they would be made more equitable. After 1991, each customer would get an equal share of its net requirements



Portion of the computer printout at left is from one of many computer runs that helped shape BPA's first draft of allocations policy. Opposite page shows third powerhouse at Grand Coulee Dam and aerial view of Washington Public Power Supply System nuclear unit No. 2 with its six circular mechanical draft cooling towers.

from BPA and therefore the rate impact would be equal.

- No single new load that exceeds 10,000 kW or which within 3 years of start of service grows to exceed 10,000 kW would be eligible for sharing in the Federal supply. This provision would help assure the widest possible use of Federal power.
- Fifteen percent of the total firm energy available for allocation would go into a conservation reserve. Special allocations from the reserve would be awarded to utilities that have undertaken effective conservation programs. Each utility will be given the opportunity to develop a conservation program tailored to its system and customers. The goal for each utility would be to reduce its use by at least 15 percent below what it otherwise would have been in 1989-90. Utilities would be eligible for the additional 15 percent allocation if their plans are judged by BPA to have a potential savings of 15 percent—or, if less than 15 percent, judged to be all the savings within the utility's capability. There would be provision to allow even bigger allocations rewards for greater savings.

New Rates

BPA's new wholesale power rates which are now in effect on an interim basis pending approval by FERC will—together with anticipated additional revenues from new wheeling charges to be implemented in 1980—increase BPA's revenues by the 88 percent found necessary to meet our financial obligations.

Our increased revenue needs would have been only about 40 percent if ***all*** the public power participants in the net-billed WPPSS nuclear projects had agreed to a proposal that WPPSS issue additional bonds to pay the debt service on those projects prior to commercial operation. BPA is presently committed to commence this debt service before start up. Refusal of two of the 104 participants to concur in this alternative means of financing pre-startup costs required the larger rate increase now rather than later.

Although BPA rates have had to be increased substantially, they remain among the lowest wholesale rates in the nation.

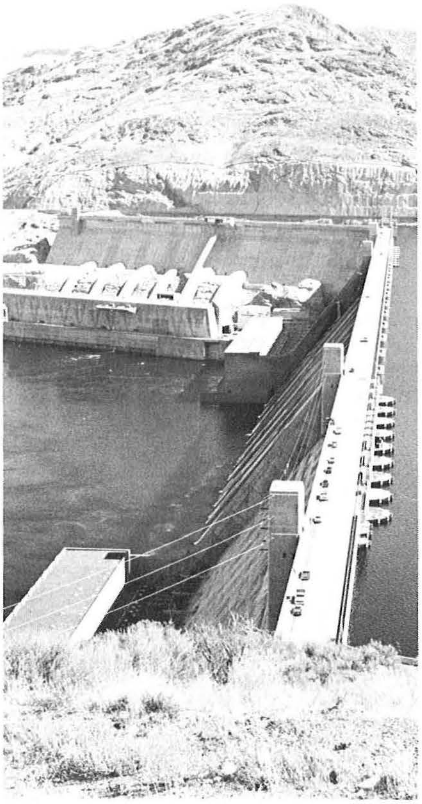
Every PUD, cooperative and municipal system in the region will be paying well below 1 cent per kilowatthour for wholesale power from BPA—the average will be close to 7/10ths of 1 cent. Most will be able to sell at retail to their ultimate customers for less than 2 cents per kWh. The national average is about 4 cents.

This is the third rate increase in BPA history. The first, in 1965, averaged 3 percent. The second, in 1974, averaged 27 percent. The way costs are rising, BPA's wholesale power rates may have to be doubled again within the next 10 years.

BPA and WPPSS

BPA and the Washington Public Power Supply System (WPPSS) both took important steps in 1979 to implement recommendations by the management consulting firm of Theodore Barry & Associates.

BPA had hired the firm to clarify BPA's oversight rights and respon-



sibilities relative to the three nuclear power projects being built by WPPSS—for which BPA has agreed to market the power and pay the costs—and to recommend ways to hold down remaining construction costs and construction time. A GAO Report in September 1979 also recommended that BPA strengthen its oversight functions.

As a result, we are insisting on more detailed budget review under the terms of the Project Agreements (the contracts between WPPSS and BPA). We soon will have more people in the field, and top BPA management is now meeting regularly with top WPPSS management and directors. It is not BPA's intent to manage the construction of the projects, but we do insist on the full exercise of our rights and responsibilities under the Project Agreements, including the right to disapprove items in the construction budget or revised budgets on the basis of the standard of Prudent Utility Practice. We also insist on accountability by WPPSS to keep within budget item costs unless otherwise approved by BPA.

Since the Barry Report, four important additional studies have been financed by WPPSS: (1) project manpower, by the Management Analysis Company; (2) a 1980 construction budget review, by Stone & Webster; (3) project management information systems, by the Boeing Company; and (4) BPA/WPPSS relationships, by the Institute of Public Administration.

While we expect these efforts to pay off in the long run by holding remaining construction costs and further schedule delays to less than what they otherwise would have been, we cannot offer evidence of any such results to date.

The current cost estimates, based on the 1980 budget, for power from these projects, when completed, range from 33 to 39 mills per kilowatthour, compared to estimates of 8.3 to 19.5 mills based on the annual costs derived from budget estimates in effect in July 1973 for Unit 2 and December 1975 for Unit 3.

The current published completion dates do not take into account construction delays suffered since January 1979, productivity trends during this period, and the effects of potential licensing delays and modifications required because of the Three Mile Island accident. Present schedules call for Unit 2, the first due for completion, to be in operation in September 1981, some 48 months behind original expectations. Delays exclusive of those associated with the Three Mile Island accident could put off that date by 10 months or more, and could add 6 to 12 months to the schedules for Units 1 and 3, each of which already is running 39 months late. Unit 1 is now scheduled for December 1983, and Unit 3 for December 1984.

However, it is important to note that Unit 2 moved ahead in 1979 from 73.7 percent complete in January to 79.7 percent in December, Unit 1 from 19.5 percent to 34.1 percent, and Unit 3 from 9.1 percent to 18.7 percent.

POWER OPERATIONS

In late 1979, passers-by got this unusual view of a very low Columbia River at The Dalles Dam. The three insets, left to right, show a power company crew restoring downed lines during the January 1979 ice storm that hit the Portland area; a barge breaking through the ice behind Bonneville Dam; and a power company employee wielding chain saw to clear fallen trees.

From Bad to Worse to Better

The year started with bad power supply conditions and ended with worse.

On January 1, 1979, the region's reservoirs were 2.2 billion kWh below normal drawdown levels. Publicly and privately owned utilities were importing power from Canada, California and the Southwest at prices as high as 63 mills per kWh—some 20 times the BPA wholesale rate then in effect.

In December, 1979, reservoirs were 8 billion kWh below where they should have been at that time of year to assure that firm loads would be met under critical water conditions. One investor-owned utility, Portland General Electric Co. (PGE), was in particular difficulty, and was importing power from as far away as Texas at more than 60 mills per kWh. There was virtually no more power to be purchased from outside the region by PGE or anybody else at any price. The region's utilities were teetering on the brink of having to ask the states to invoke the curtailment steps devised in 1977 by the Northwest governors' Pacific Northwest Electricity Task Force, but December rains forestalled the need for curtailment at least temporarily.

In early 1979, the problem had been a prolonged shutdown of the 1130-megawatt Trojan nuclear power plant and resultant loss of regional power supply that streamflows were not sufficient to overcome. Record cold winter weather compounded the problem. During this period, streamflows were well above the critical levels on which regional power planning is based, but nevertheless were only 88 percent of "normal." Trojan had been routinely shut down for refueling in March 1978, and was scheduled to return to service in May. But a lengthy Nuclear Regulatory Commission (NRC) safety hearing kept it out of service until January 2, 1979. Trojan's return to service after 9 months of no power production saved the region from worse problems that could have been encountered that winter.

In late 1979, the problem was another prolonged shutdown of Trojan, combined with even poorer streamflows. This time Trojan had been shut down since October 12 for repairing steam generator leaks and other work. When it was ready to resume operation in early December the Atomic Safety Licensing Board ordered another public hearing in late December before authorizing its start-up subject to concurrence by the NRC staff. That concurrence came December 29, 1979, and Trojan was back in full operation a few days later after some customary mechanical problems in startup.

Trojan's return to service early in 1980 eased the serious supply problems threatening the region and early January 1980 snowpack measurements further improved the outlook.

The 1978-79 Winter

November and December 1978 were among the coldest months ever recorded in the Northwest, and January 1979 was the coldest January of the century.

Consequently 10 daily BPA system load peaks and 10 hourly load peaks were set during the three




months. But the final 1978-79 records didn't come until February 2, 1979, when both 1-hour and 24-hour peaks of 10,986 mW and 232,491 mWh, respectively, were established.

These numbers apply only to BPA loads. By definition, that means just our sales to non-generating utilities, industries and Federal agencies. Generating utilities report their own loads separately as the combined total served by their own generation and generation purchased from BPA or others. Taking into account BPA sales to generating utilities, the Federal system set a one-hour generating peak of 15,419 mW on February 2 and a 24-hour record of 313,149 mWh on May 25, 1979.

Sales of non-firm (secondary) energy to preference customers had to be stopped November 21, 1978, but were restored at midnight January 19, 1979. Deliveries of interruptible energy to the industries served directly by BPA were stopped on October 24, 1978, and not resumed until March 9, 1979. Sales of non-firm power to the investor-owned utilities also were resumed March 9, after having been interrupted on the previous October 24.

Advance energy deliveries from BPA, and energy from the dual-purpose reactor at Hanford and other sources enabled the industries to continue full operations during the period of interrupted supply. When interruptible power was restored, the industries reassigned their Hanford entitlement to BPA for sale with recallable provision for 1980 use. Northwest utilities did not need that energy, so it was sold outside the region.

Meanwhile, winter ice storms knocked down many utility distribution lines, mainly in the Portland-Vancouver area.

A wetter-than-usual February turned things around for a time, but then the situation worsened again and on July 31, at the end of the 1978-79 refill period, reservoirs were 4.4 billion kWh short of full. Full is the normal level for that date.

Fish Flows

During May, the Federal Columbia River Power System discharged water to assist in the downstream migration of juvenile fish. This required BPA to market secondary and surplus energy that otherwise would have been conserved to help refill reservoirs.

Between May 7 and May 31, BPA marketed outside the region 392,467 mWh of surplus power generated in the course of satisfying the Columbia and Snake River minimum streamflows requested by the fishery agencies. We also stored some excess generation in California and Canada.

This was the first time since September 1978 that BPA had sold surplus energy to the Pacific Southwest— it was energy in excess of all Northwest markets and could not be stored.

BPA revenue losses and costs attributable to the spring juvenile fish outmigration are estimated to be about $2.5 million. Revenue losses included 350,000 mWh of outright spill valued at 3 mills per kWh. If we were to value this energy at a replacement cost of 35 mills per kWh, it would have amounted to

Source and Disposition of Total Energy Handled by BPA
Fiscal Year 1979 Total 145.7 Billion KWH

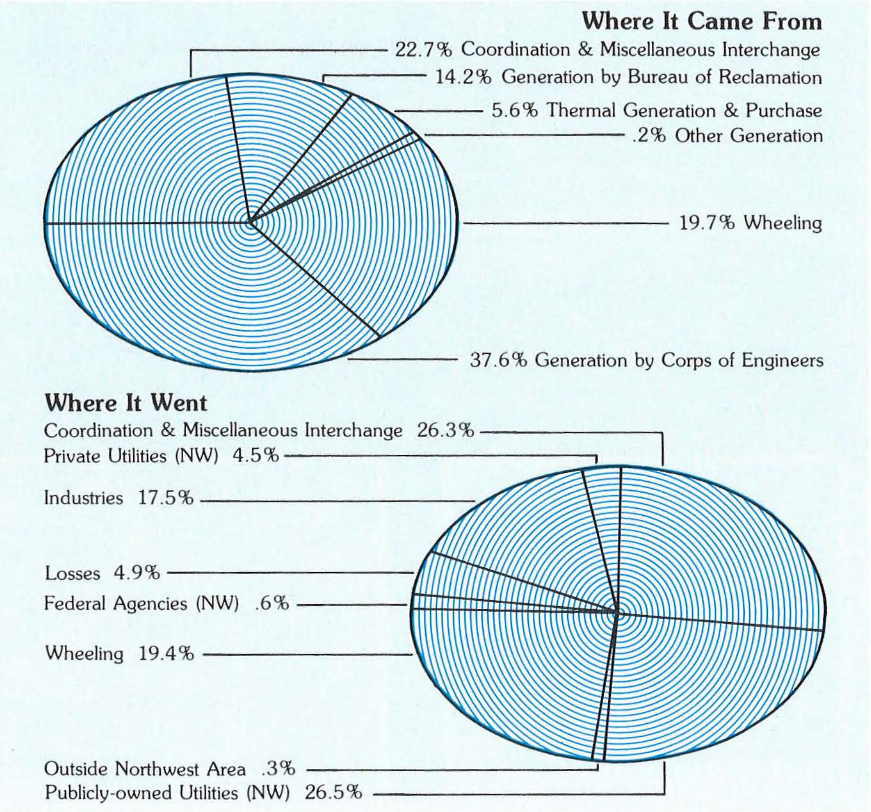


Chart at left shows where BPA's energy supplies came from and where they went in 1979. Table at right shows how target dates for the region's scheduled thermal power projects have slipped in the past year and since inception of the projects.

about $14 million. Costs include 561,870 mWh of energy stored with B.C. Hydro at an average cost of 2.5 mills upon return, and 76,658 mWh stored in California at a cost of 1-mill, plus 11,092 mWh of transmission losses on California storage valued at 3 mills. All of the energy stored with B.C. Hydro was returned by August 31 and the energy stored in California was expected to be returned by June 30, 1980.

The 1979-80 Year

As the 1979-80 operating year approached, streamflow conditions and the outlook for refill of the region's reservoirs required BPA to curtail secondary energy deliveries. We interrupted deliveries to investor-owned utilities June 29, industrial loads July 1, and preference customers July 6, 1979.

The industries were able to obtain substitute power for most of the interrupted industrial load through mid-December, 1979, although Alcoa had to shut down one potline in September and other industrial customers reduced their use by up to 12 percent beginning in October. The bulk of the industrial interruptible load was served by industry purchase of hydro energy from B.C. Hydro and Cominco, cogeneration from Weyerhaeuser and Longview Fibre, nuclear power from Hanford, and by BPA advancing energy from Federal reservoirs. The industries paid as much as 35 mills per kWh for the Canadian hydro and as much as 27 mills for the cogeneration.

BPA advances to replace interrupted power are covered by contracts which require the advanced energy to be returned if needed later to serve BPA firm loads or to restore reservoir levels. Such advances of energy to the industries began October 16 and amounted to about 800,000 mWh, or seven weeks of operating power for the industries. So, by early December, the industries were back to reliance on Hanford, Weyerhaeuser and imported power, and by the end of the month had further reduced operations and laid off more workers. The outlook for these industries on January 1, 1980, was for further production cutbacks.

While reservoirs were far below desired operating levels at the end of 1979, BPA did not anticipate problems in meeting its own peak or firm energy loads for the balance of the winter.

Meanwhile, at year's end, prior to return of Trojan to service, PGE was receiving assistance from utilities inside and out of the region. The "one-short-all-short" concept guiding the region's utilities in their planning and operations was on the verge of being tested for the first time, as it appeared that the situation could still require some curtailments regionwide to spread the impact evenly.

Emergency Plan

If regionwide curtailment becomes necessary, the 1977 plan of the governors' task force—which may have to be updated—calls for two stages of voluntary curtailment and three stages of mandatory curtailment. That plan was put together not only to cope with the exigencies of 1977 but in recognition that delays in construction schedules for thermal projects could require its use

Installation Schedule for Thermal Power Projects

Plant	Principal Sponsor[1]	Nameplate Rating Megawatts	Status & Percent Complete[2]	Probable Energy Date[7] As of 1/1/1980	Probable Energy Date[7] 1979 WGF[6]	Initial Scheduled Date	Delay Months From 1979 WGF[6]	Delay Months From Initial Sched. Date
Boardman	PGE	477[4]	UC-95	Nov 1980	Nov 1980	Jul 1978	—	28
WNP #2	WPPSS	1100	UC-80	May 1982	Sep 1981	Sep 1977	8	56
Colstrip #3	PSPL	456[3]	X	Jan 1984	Jul 1983	Sep 1978	6	64
WNP #1	WPPSS	1250[5]	UC-34	Nov 1984	Dec 1983	Sep 1980	11	50
Colstrip #4	PSPL	456[3]	X	Nov 1984	May 1984	Sep 1979	6	62
WNP #3	WPPSS	1240	UC-19	Sep 1985	Mar 1985	Sep 1981	5	48
WNP #4	WPPSS	1250[5]	UC-12	Jan 1986	Jun 1985	Mar 1982	7	46
WNP #5	WPPSS	1240	UC- 8	Jul 1986	Jun 1986	Mar 1983	1	40
Skagit #1	PSPL	1260	X	Nov 1989	Nov 1986	Jul 1981	36	100
Pebble Springs #1	PGE	1288	X	Jul 1990	Mar 1987	Sep 1980	40	118
Skagit #2	PSPL	1288	X	Nov 1991	Nov 1988	Jul 1984	36	88
Pebble Springs #2	PGE	1260	X	Jul 1992	Apr 1989	Jul 1985	39	84

[1] Abbreviations are: PGE - Portland General Electric Co.; PSPL - Puget Sound Power & Light Co., WPPSS - Washington Public Power Supply System; IPC - Idaho Power Co.
[2] UC - Under construction; X - Committed.
[3] Colstrip Units #3 and #4 are rated 700 MW each; 65.1% will be used by West Group Area (1980 WGF).
[4] Boardman is rated 530 MW and 90% will be used by West Group Area. The remaining 10% will be Idaho Power Co.'s share.
[5] WNP #1 and #4 are initially rated at 1220 MW. After their first fuel cycle, their ratings will increase to 1250 MW.
[6] WGF - West Group Forecast.
[7] These dates are West Group Forecast dates computed from trend analysis based on actual project milestone completion dates and do not necessarily agree with owners' scheduled completion dates.

anytime in the next decade.

As to ***voluntary*** curtailment, Stage 1 includes utilities and governmental units curtailing their own uses and seeking voluntary curtailment by all large customers. It also includes appeals to all customers via newspapers, radio and TV. Stage 2 includes all of those measures plus urgent appeals regarding specific measures to be taken by all customers, including 65 degree thermostat settings for daytime heating and 55 degrees at night, 85 degrees for cooling, and 120 degrees for water heating. Stage 2 also calls for elimination of swimming pool heating, window and outdoor display lighting, including parking lots and street lighting not needed for safety.

As to ***mandatory*** curtailment, Stage 1 makes all of the above voluntary steps mandatory. It also restricts lighting for sports events and restricts operation by retail, commercial, industrial and governmental users.

Stage 2 of mandatory curtailment requires all customers to curtail electric consumption by the amount necessary to bring resources and requirements into balance. Each customer is given a quota for monthly use. Utilities could discontinue service if necessary. The BPA Administrator would make no further advance energy sales to industries and would develop a plan to assure prompt return of all outstanding advance energy. All available federal and non-Federal generating plants would be operated to serve the needs of deficient utilities.

Stage 3 includes interruption of service to all customers on a rotating basis, ordering large industrial customers to curtail by a fixed percentage and certain large customers to cease operation for the duration of the emergency.

Exemptions include hospitals, nursing homes and other health facilities, police and fire stations, communication facilities, sewage treatment and pollution control facilities, airports, domestic water pumping installations and such energy facilities as refineries, oil and gas pipelines and coal handling facilities.

The Long Term

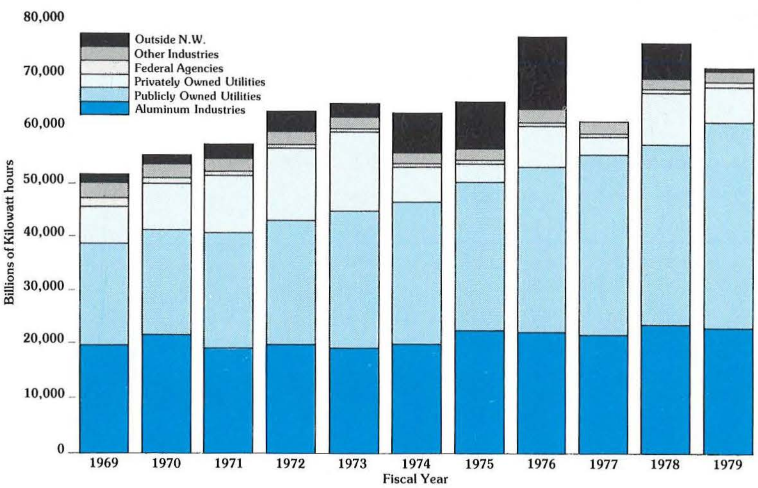
The longer term outlook appears to be as bleak, perhaps more so.

As shown in the attached table, construction schedules have slipped further behind the ones published a year ago, just as the ones published a year ago had slipped badly from the original schedules.

Construction schedule slippages— not poor streamflows— lie at the heart of the region's power supply problems. In our planning for resources sufficient to meet loads, neither BPA nor the region's utilities count on more hydro than can be produced under "critical" streamflow conditions, which is to say the lowest of record over a sustained period. Then we schedule thermal projects to meet the difference between firm hydro expectations and projected loads.

So when we run into shortages, it is not because streamflows are low, but because the region's thermal projects are not coming on line on schedule. To the extent that streamflows are better than "critical," we have extra power to sell. We make

BPA Sales of Electric Energy



Graph at left shows sales of BPA electricity to various categories of customers. Hydrograph on opposite page shows that streamflows in first 6 months of 1979-80 operating year were near 1936-37 record lows. Low streamflows were the major reason why the region's reservoirs were far below normal operating levels from July through December.

good use of it by selling it in this region to displace more expensive thermal generation and in California to save oil, while at the same time producing revenues that help keep firm power rates lower than they otherwise would be.

Based on construction schedules announced earlier in 1979, the region faced energy deficits in every year in the decade of the '80s under critical water conditions. The threatened shortages loomed as large as the output of three big thermal plants in one year, 1983-84.

But since those schedules were published, Puget Sound Power and Light Co. announced a delay of at least 2 to 3 years more in the schedule for its two Skagit nuclear units. Further, the State of Oregon adopted a moratorium on the licensing of nuclear plants until November 1980, which can only delay the published schedule for startup of two PGE nuclear units at Pebble Springs.

In light of the continued uncertainty regarding construction schedules and the extent to which conservation measures will succeed in reducing consumption, BPA confesses to inability to predict with any certainty the depth of the deficits in the '80s and, of course, there is nothing yet scheduled in the region for the '90s.

Forecasting

Forecasting future electric power demand never has been an exact science, but neither has it ever been so difficult. Conservation results are hard to assess, and unexpected loads keep cropping up. For example, in its "Energy 1990" plan, Seattle City Light never anticipated a newly indicated 30-mW Boeing load or a new application from Bethlehem Steel for 80 mW. And only recently could a Clark County PUD anticipate the influx of electronics industries that has revealed itself in the past year or two.

Nevertheless, for several years now the combined utility forecasts of future needs keep adding up to lower totals for the region than the previous year's. Some utilities are even discussing with state utility commissions new regulations that would prohibit electric heat hookups. Even so, because of construction schedule slippages, the projected deficits keep looming larger.

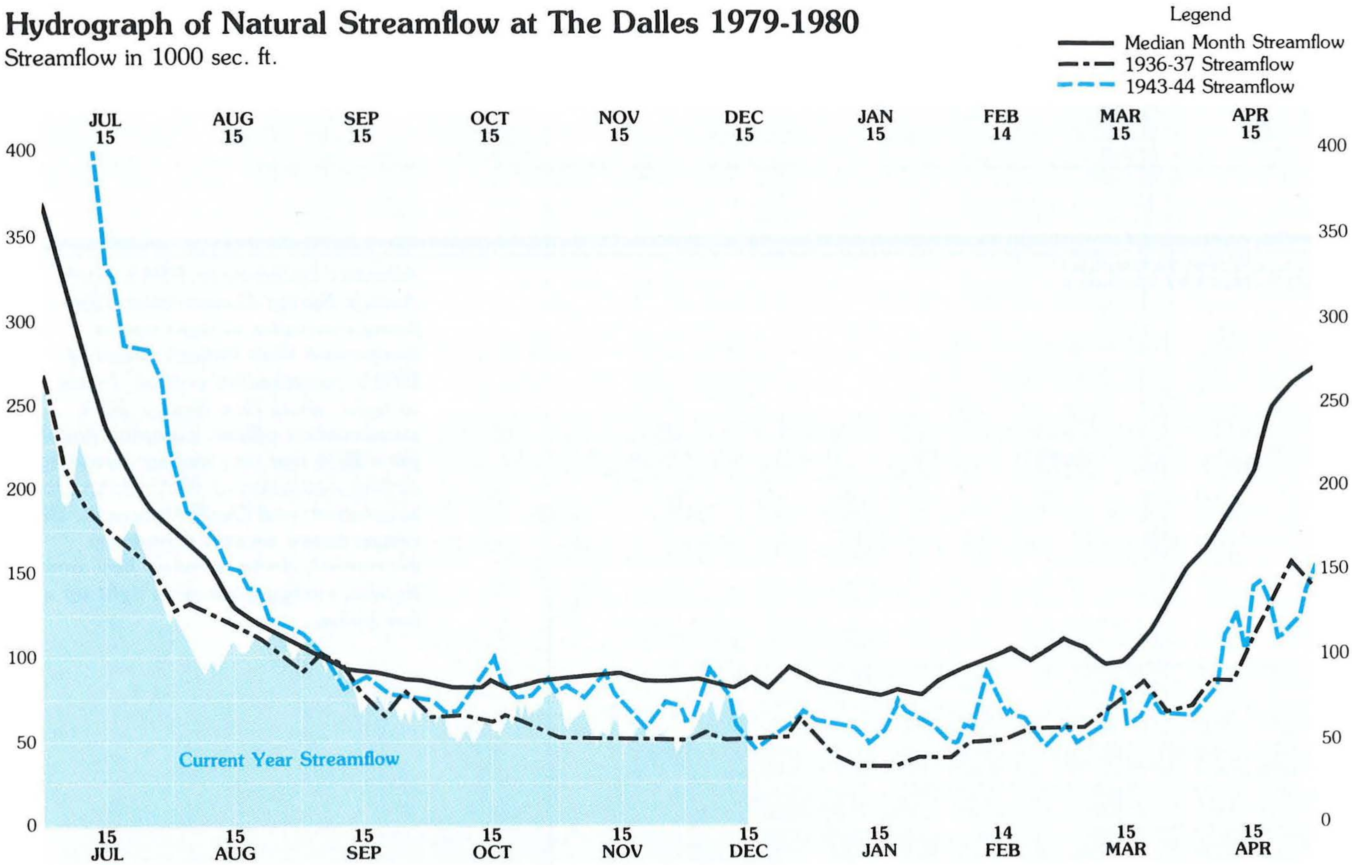
Meanwhile, ever-higher oil prices and supply uncertainties put increasing pressures on homeowners to convert from oil heat to natural gas or electricity. Our region, our nation, soon may get to the day of wide use of the electric car.

BPA and the Pacific Northwest Utilities Conference Committee (PNUCC) in recent years have tried to improve their forecasting results with better tools, particularly computer models reflecting more of the type of non-utility input we are getting from our "Delphi" workshops involving participants from the states, universities and other groups throughout the region. BPA and the utilities are developing end-use data to help improve forecasts and to serve as a benchmark for measuring conservation.

The Delphi workshop input from non-utility people is used to make an econometric model to test and cross-check the official forecast. The official forecast is the sum of individual utility forecasts which take into account population growth, past

Hydrograph of Natural Streamflow at The Dalles 1979-1980

Streamflow in 1000 sec. ft.



energy use, business trends and other factors. Thus far, the econometric model cross-check has tended to produce forecasts not greatly different from the official one.

The regional power planning procedure called for in the pending regional power bill would require even more non-utility input than the present system.

Sales

Poor water conditions, with streamflows at near-record lows the last two months of Fiscal Year 1979, were responsible for the 6 percent decrease in energy sales below FY 1978 levels. Energy sales totaling 72,023,331,000 kWh were down compared to FY 1978 sales of 76.5 billion kWh. The average revenue from the sale of energy to all classes of customer was 3.39 mills per kWh, compared to 3.27 mills for the previous year.

In the Pacific Northwest, BPA preference customers, including public and peoples' utility districts, cooperatives and municipal systems, purchased 38.7 billion kWh of energy and associated capacity during the fiscal year. Purchases by preference customers accounted for 53.8 percent of total BPA sales, compared to 44 percent in FY 1978.

Representing 9 percent of total sales, BPA sold only 6.5 billion kWh of energy to investor-owned utilities during FY 1979, a decline from 9.8 billion in FY 1978.

BPA supplied Federal agencies in the Pacific Northwest with 850.2 million kWh in FY 1979, a 14 percent increase over 745.7 million kWh in FY 1978. Federal agencies account for about 1 percent of total BPA sales.

Sales to the aluminum industry, which represented 32.4 percent of BPA sales, totaled over 23 billion kWh during FY 1979. Compared to FY 1978 this was a slight decrease from nearly 24 billion kWh.

During FY 1979, BPA's other direct service industrial customers purchased 3 percent of BPA's energy, totaling nearly 2.1 billion kWh, the same as FY 1978.

In FY 1979, sales outside the Northwest region were 392.5 million kWh, compared to 6.2 billion kWh in FY 1978. Representing less than 1 percent of all BPA sales, this sharp decline was due to there being less BPA surplus energy.

CONSERVATION

Attentive audience at BPA's Sixth Annual Spring Conservation Conference includes in right center foreground Walt Pollock, head of BPA's conservation section. Insets, left to right, show Don Davey, BPA conservation officer, pumping gasohol for a BPA test car; worker installing ceiling insulation at BPA's John Day substation; and Geoff Moorman, BPA conservation section superisory economist, demonstrating how much human energy it takes to light up a few bulbs.

Not Just Waiting

We have launched four important conservation pilot programs. One will insulate 2500 homes over the next two years. Another will help pay for 400 to 600 solar water heaters. The third will install 12 small windmills. The fourth will test several hundred irrigation pumps.

DOE, OMB and Congressional committee concurrences were completed in October to allow us to move forward on these pilot projects. We await necessary statutory authorization to invest large sums in bigger conservation programs on more than a pilot basis.

While waiting for that green light, we also:

• Finished auditing all 205 BPA-owned buildings of 1,000 square feet or more, and completed or are in the process of retrofitting 30 of them.

• Added four Lectric Leopards to our current fleet of three Electra Vans which we are operating on a test basis.

• Launched a gasohol test program using 10 percent and 20 percent mixtures of methanol and unleaded gasoline in nine vehicles.

• Installed a solar heating and cooling system at our Big Eddy Substation at The Dalles, Oregon.

• Achieved further reductions in line losses on our extra-high voltage transmission system.

• Sponsored our Sixth Annual Spring Energy Conservation Conference.

• Proposed a 15 percent conservation reserve as part of the draft allocations policy to ration available Federal power supplies (see page 8).

Pilot Projects

The insulation pilot program is a joint effort among BPA and its public power utility customers. BPA will fund it and the participating utilities will carry it out.

We will invest between \$2.8 and \$4.3 million over the next 2 years. It will finance home energy audits and interest-free loans for cost-effective weatherization measures.

The relative handful of participating utilities is limited in number by the amount of money available to BPA, not by lack of interest.

In addition to achieving savings of about 10 million kWh annually, we expect to gain valuable practical experience in working through our utility customers to achieve conservation savings. And we expect what we learn will save us and the other utilities time and money and headaches when it comes to enlarging these pilot programs nationwide.

The pilot solar water heating program will cost between \$1.2 and \$2.4 million. Each solar water heater is expected to save about one-half of the household's annual requirements for electricity for water heating. BPA will pay \$700 per solar water heater installation. That represents our estimate of the value to BPA in terms of investment we would have to make to acquire the same amount of energy from a new power plant. based not on our low wholesale rates but on the estimated average cost of a coal or nuclear project if started now.

As for pump testing, we started that pilot program on a preliminary basis in late summer and completed testing about 200 irrigation pumps.

They tested out at about 51 percent efficiency on average. Efficiency on the order of 60-65 percent is a practical goal. There are more than 20,000 irrigation customers who consume some 2 billion kWh annually. We believe the pilot testing program through our utility customers will inspire enough of them to upgrade their equipment to achieve savings to themselves and to BPA far in excess of the estimated $140,000 total cost of the 2-year pilot program.

In the windmill pilot program, we expect to spend about $155,000 to finance installation of a dozen small windmills. That will let us determine the extent to which wind-generated electricity on a small scale at individual farms and residences can displace part of the need for electricity supplied by utilities.

It will also help determine the extent to which surplus electricity from small wind machines can be fed back into the grid to help serve other loads of the local utility.

The first of these units should be in place this spring and all 12 by the end of 1980.

Infrared Photos

Our infrared aerial photography program to pinpoint heat loss and help utilities encourage their customers to take cost-effective weatherization measures is now in its fourth winter. Some or all of the service territories of 30 percent of the region's utilities were photographed during the first three years. Most of the participating utilities report that use of the photographs has helped in their efforts to stimulate customer interest in energy-saving weatherization measures.

Our goal this winter is to finish photographing all or parts of the service territories of utilities that either chose not to participate in prior years or who were shut out by unsuitable weather conditions. The best photographs are obtained on cold, clear nights with no snow on the rooftops, and no precipitation. Nights such as that are few and far between on the coast side of the mountains of Oregon and Washington.

Midway Test

We have a conservation test project underway at 18 houses at Midway Substation where in the '40s a small community was established for our employees because of the substation's remote location.

Six of the homes have been insulated for the test program. Six others have been more completely weatherized with double-glazed windows and weatherstripping in addition to insulation. The remaining six—the control group—have not been modified and will be used for comparison purposes in the careful monitoring of all 18.

In another phase of the Midway test program, we are comparing the effectiveness of four different types of solar hot water heaters, five systems that combine heat pumps with hot water systems, and four "point of use" water heating systems.

ALTERNATIVE & RENEWABLE RESOURCES

Giant logs in foreground and wigwam burner in background dramatize the potential for power generation from mill wastes and other forest products in our region. Wigwam burners would no longer be needed if mill wastes were used to run generators instead. Inset photos show three hands full of different types of wood fuel that can be burned to generate electricity, left to right, hog fuel (mostly bark), wood chips and sawdust (mill residue).

A Big First

If all goes well, construction will start in May, 1980, on the first of three giant windmills to be installed by DOE on the BPA system, and first power could flow as early as December, 1980.

Located near Goldendale, Washington, in the Goodnoe Hills, they will be the largest windmills ever built anywhere in the world.

Each will have a 300-foot long blade mounted on a 200-foot tower. Each will generate 2.5 megawatts of electricity. When all three are completed — the schedule calls for mid-1981 — they will produce enough electricity to serve about 2000 average homes.

Measured against the output of a conventional or nuclear thermal power plant, the output is small. Considering that the wind does not blow all the time, it would take approximately 800 windmills of this size to produce the equivalent of one big thermal power plant of 1000 mW capacity.

Still, it is BPA's and the nation's biggest venture into harnessing the power of the wind.

These are the MOD-2 wind turbines being developed for DOE by the Boeing Company under the technical management of NASA's Lewis Research Center. BPA will manage the units and conduct field tests as the energy is integrated into the region's distribution system. Some 20 subcontractors from 16 states and Sweden are making the components.

Each of the three prototypes will cost about $4.6 million, but mass production would be expected to bring the cost down to $2 million each. At that price, these windmills would be more competitive with such conventional alternatives as coal and nuclear.

Smaller Steps

While the windmills project is the biggest and most exciting BPA step into the world of alternative and renewable resources, it is not our only step in that direction.

However, as with conservation programs, until we get additional statutory authorization the things we are doing to hasten the day when these new methods make an appreciable addition to our power supplies necessarily have to be restricted. Still:

- We installed solar panels at the Big Eddy Substation near The Dalles, Oregon. This $420,000 solar heating and cooling system could become a model for solar applications in Federal buildings throughout the country.
- Since 1975 we have been funding research by Oregon State University to study where the wind blows hard enough — but not too hard — and steadily enough to power windmills. Then when large wind machines enter the commercial market, we will have the sites mapped out and tested. We have anemometers at more than 100 potential wind sites throughout the Northwest and we are gathering hourly information on 25 of the best sites.
- We are awaiting the second phase report of our cogeneration consultant whose first phase work uncovered a potential of about 1,000 megawatts of cogeneration at industrial locations scattered throughout the region, on top of the

approximately 400 megawatts of cogeneration already in place. The second phase study analyzed the economic and cost aspects of 16 sample industrial sites, representative of major industrial sectors. Preliminary results indicate a range of energy costs from 25 to 60 mills per kWh based on typical public agency tax exempt revenue bond financing. Energy costs based on industrial or private utility financing would be higher.

• We are co-funding feasibility studies for two possible cogeneration or biomass waste generation projects. One is in Oregon with the Columbia Basin Electric Co-op, the Kinzua Corporation, and the Electric Power Research Institute (EPRI). The other is in Washington with Lewis County, the Lewis County PUD, eight lumber mills in the immediate vicinity and EPRI.

• Seattle City Light is growing alder on 20 acres of BPA right-of-way in a biomass tree-farm experiment.

• We are participating with other DOE agencies and regional utilities in evaluating the technical and economic feasibility of generating geothermal power in Raft River Rural Electric Cooperative territory in southern Idaho.

• We also are taking a hard look at the potential for direct use of geothermally heated water in homes, businesses and industry. This technology is already in use in our region, in Klamath Falls and Boise, for example.

The "A" Teams

Because we know there may be an enormous amount of potential just waiting to be developed in the way of alternative and renewable resources, we established several resource assessment teams within BPA during 1979.

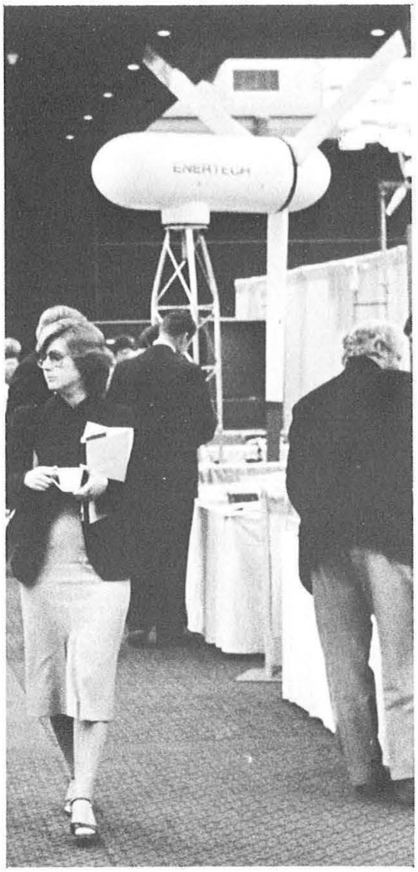
One is studying low-head hydro potential. Another is looking into pumped storage. Others are investigating fuel cells, magnetohydrodynamics (MHD), storage systems, geothermal, wind, solar, ocean power, biomass, cogeneration, and synthetic fuels. Their preliminary reports are due early in 1980.

The Columbia River system can act as a giant storage battery to make development of alternative and renewable resources more feasible here than in some other region.

The major focus of these assessment teams at the moment is on the near term options which can make an impact on the region's energy supply during the '80s. As noted in the Power Operations section, shortages loom all through the '80s, especially in the mid-'80s. Long lead times rule out the hope that coal or nuclear plants started now can be finished in time to overcome those shortages. But we believe fast action on some alternatives and renewable resources projects could help. Cogeneration, biomass, small hydro, wind, solar heating and cooling, and geothermal direct heat applications all seem to fall into this category.

Resources which from presently available data do not appear capable of making a contribution until after 1990 include geothermal electric, fuel cells, MHD, solar central station and ocean power. Storage technology being studied includes pumped hydro, batteries, compressed air, flywheels and magnets.

The resource assessment teams



Far left photo shows Administrator Sterling Munro and Chief Engineer Ralph Gens inspecting installation of solar panels at BPA Big Eddy Substation. Next photo shows part of crowd around model windmill on display at the region's First Annual Alternative and Renewable Resources Conference sponsored by BPA and the energy offices of the four Northwest states. Group of regional maps on opposite page show, top row left to right, where the sun shines most, where the wind blows best (April–June only), where the direct-use geothermal potential lies; and bottom row, left to right, where the forests grow; where the solid waste can be recovered, and where the degree days—indicating the need for wintertime heating—are greatest.

are establishing data for each of these resources for projects existing, under construction and planned, as well as for potential. The idea is to develop a regional data base full of facts on the technical, economic, cost and environmental considerations. The data is being gathered from literature, utilities and industries, state and Federal agencies and through contracts with consulting firms.

Earlier Studies

We know some things already about the potential for alternative and renewable resources on the basis of earlier studies by BPA and others, including our consultants.

As noted, a consultant has identified 1000 mW of additional cogeneration potential for the region, and from preliminary assessment work we believe that there is additional potential for electric production from burning forest slash and mill residue, although more expensive.

The Northwest Energy Policy Project (NEPP), completed in 1978 under sponsorship of the Northwest governors, identified approximately 2000 mW of realistic potential from solar power in the region by the year 2000. In addition to central station systems which actually produce electricity, the NEPP study found that smaller individual passive and active solar systems which do not produce electricity, but which could displace some electricity through direct applications such as space heating and hot water heating, are promising.

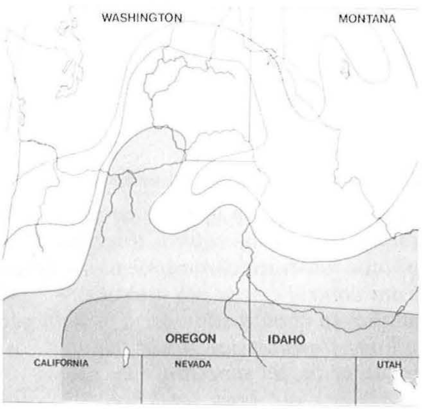
The same NEPP study shows about the same potential — 2000 mW or the output of two large coal or nuclear plants — for wind generation in the next 20 years, and about 550 mW for geothermal electric generation.

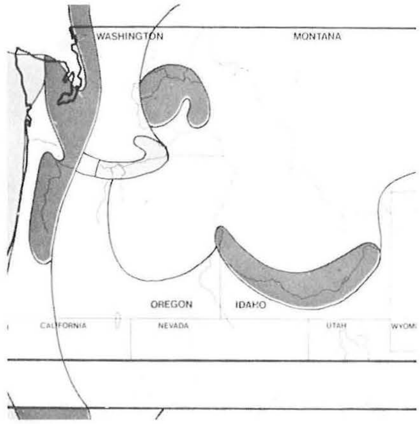
As for low-head hydro, the Corps of Engineers and DOE, through the Northwest states, have completed potential assessments. On a theoretical level, the DOE estimates are quite cheering — 22,915 mW for the region with availability 50 percent of the time. But a preliminary screening for environmental and economic feasibility and other considerations cut this potential to a fraction — some 1,973 mW — and further refinement will make the practical potential even smaller. On the other hand, we believe that the DOE program for loans to utilities and others to make feasibility studies for low-head projects will help assure maximum feasible development. DOE is currently funding feasibility studies for six low-head sites in the region.

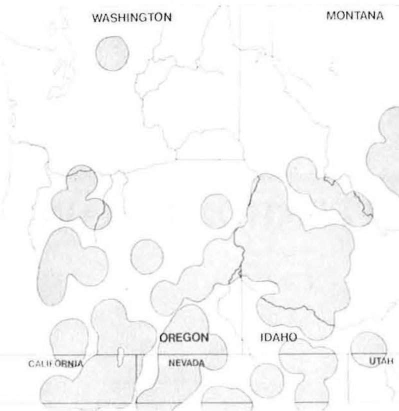
Another First

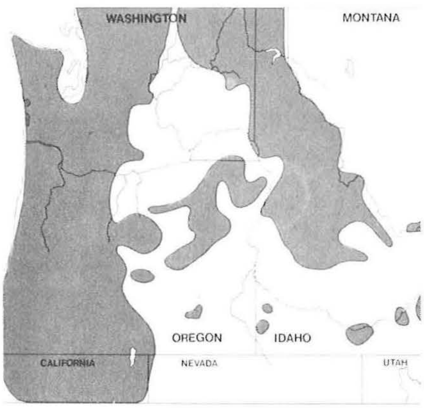
In mid-October, BPA and the energy offices of the four Northwest states sponsored the region's First Annual Alternative and Renewable Energy Resources Conference. More than 350 persons came to Seattle for the event, including 91 representatives of Northwest utilities. There also were representatives of environmental and consumer groups; government officials from the state, local and Federal levels; consultants, manufacturers and sales reps — even a firm of chimney sweeps.

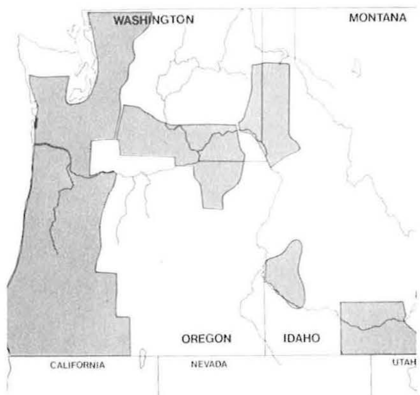
Governor Dixy Lee Ray of Washington sounded the keynote, declaring: "Sometimes, in using the word alternative, there may be the implication that conventional sources now

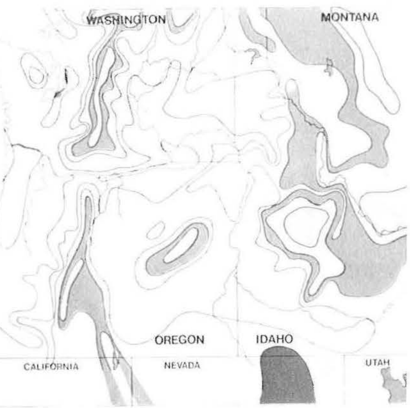












being used are not needed, and that an alternative source would in fact be a substitute. The fact is that we need to develop additional and diversified sources because we need to have as many different ways of producing fuel and electricity as we possibly can."

Many speakers stressed the need for cooperation between utilities, industry, and government in order to bring on line the vast numbers of small installations necessary if alternative energy resources are to make a significant contribution. Fred Adair, Washington State legislature aide, put it this way:

"Getting more BTUs on line from renewable resources is like filling a bathtub with a teaspoon. If I tried to do that myself, it'd be overwhelming, but if each of you had a teaspoon, we could fill the tub in about 150 trips, and thereby bring the job down to manageable proportions."

The Bonneville Administrator addressed the same theme, saying BPA will be numbered among "Them That's Doing," but that there is "no way a BPA or an individual utility can do the job alone."

BPA Policy

The Bonneville Administrator used the Seattle conference to state BPA's current policy with respect to alternative and renewable resources:

"First, we will provide transmission services, storage and backup for any utility in the region that wishes to undertake a renewable resources project, and we will help them market the power.

"Second, we will — under present authorities — purchase, until 1983, the output of ***any*** cost-effective renewable resources project that ***anybody*** can bring on line in our region prior to then.

"Third, to encourage others, we will continue to sponsor conferences such as this and make studies ourselves and hire consultants to develop data on the cost-effectiveness and environmental acceptability of renewable resources.

"Fourth, we will sponsor pilot programs for solar water heaters and family-size windmills and other small-is-beautiful direct applications of renewable resources.

"Fifth, and finally, we will continue to work for passage of a regional power bill that will untie Bonneville's hands and let us be a prime mover in putting renewables to work in our region."

OPERATION & MAINTENANCE

Against backdrop of huge transmission tower ready to be raised, three inset photos illustrate communications flow from control center via microwave station to construction crew to help get a huge transmission tower put together or, as sometimes is necessary, put back together.

Foolproof ? No Such Thing

John Henry says in the song, "if the left hand don't get you, the right one weel."

That's the way it is with operating and maintaining a bulk power system.

There's just no such thing as a fail-safe system. You design and build it with reliability as a major objective. That means you build it to protect against nearly all lightning strikes, nearly all ice storms, nearly all wind storms, nearly all mechanical failures, and nearly all human error.

Because it is not possible to make it 100 percent foolproof, outages occasionally happen for all of those reasons. Sabotage and vandalism compound the O&M problem. Murphy's law compounds it further.

Major Disturbance

A case in point is the major system disturbances on November 29, 1979, that separated the interconnected western states into seven separate areas and left 340,000 people without power for up to two hours.

It shouldn't have happened. The triggering human error alone would not have caused the system breakup but for a related event.

While the official investigation, analysis and report of the Western Systems Coordinating Council (WSCC—a group of 46 interconnected utilities and 13 affiliate members in the 11 Western states) is not yet complete, there was substantial information available immediately to answer many questions about the event.

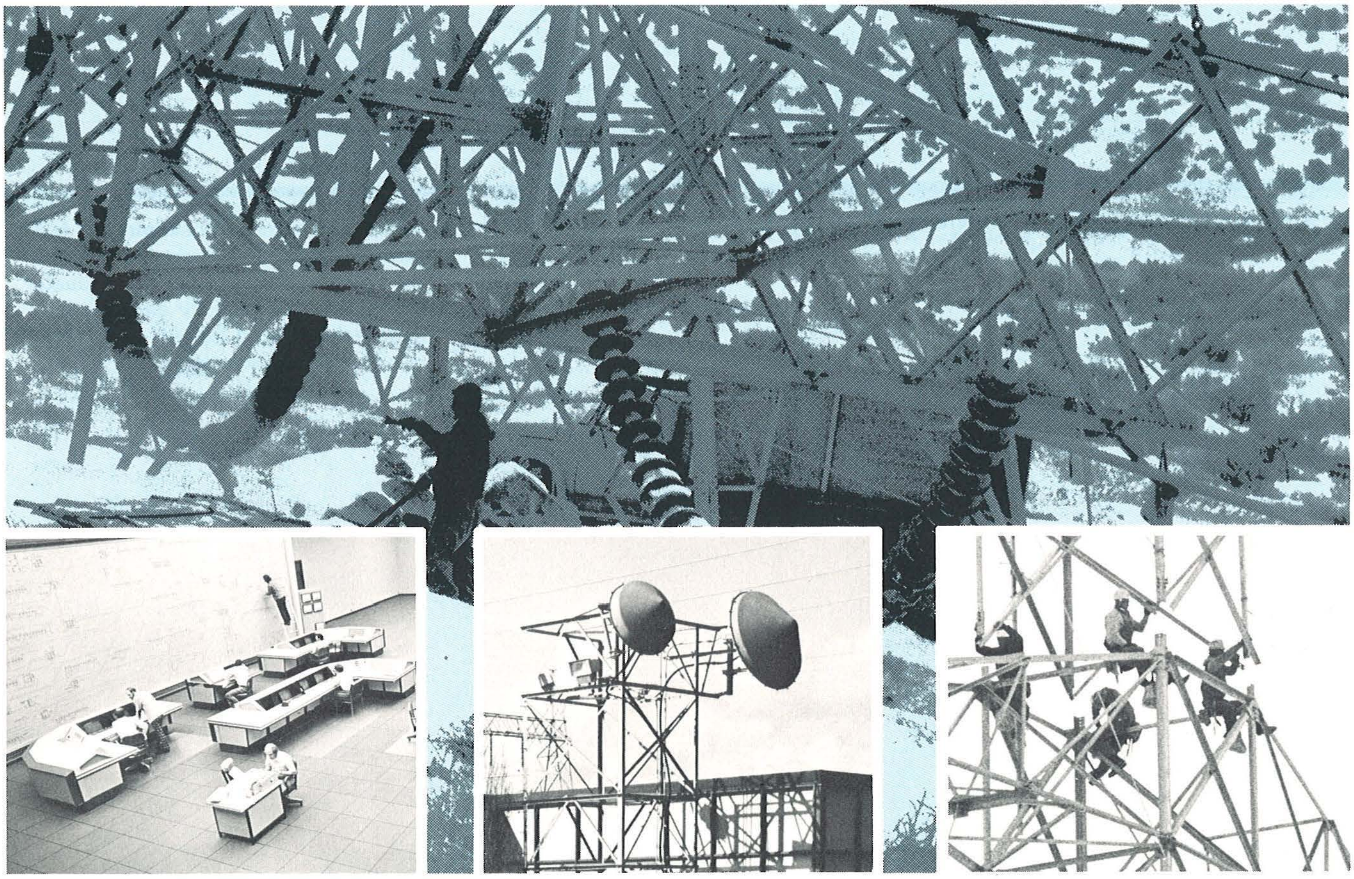
It all started when a technician at Grand Coulee threw an auxiliary switch on a unit that was out of service for maintenance. The same switch controlled the information flow between the switchyard and the powerhouse for operating generators. The interruption of intelligence flow caused a preprogrammed reduction in the level of output from the third power plant generators in service at the time. Ordinarily, this would have resulted in automatic adjustments to restore balance between system generation and loads.

But now enter another factor. Many months earlier, the Pacific Northwest-Pacific Southwest intertie had been scheduled for an outage to allow construction of a section of the Slatt-Marion 500-kV line crossing the intertie lines. Power flow and stability studies were made back then to determine what would happen in various situations including approximately the very one that did happen. But between the date of the study and the outage, the actual load flows on the system changed from those assumed for the study. When the triggering event occurred, the remaining system was loaded far beyond the amounts indicated in the studies. What couldn't happen did happen—the system separated.

We will take such steps as appropriate to further improve system reliability in light of results of the WSCC investigation now underway.

Vandalism

Vandalism is a never-ending problem on a power system. It has blacked out communities and risked human life. It costs large sums. The vandalism repair bill for BPA, paid by the region's ratepayers, totals more than $1 million for just the



past 5 years.

Broken windows, smashed gates and illegal trespass are bad enough. Particularly costly — and particularly dangerous to innocent bystanders, and even to the perpetrators — is the foolish shooting of conductors and insulators on BPA lines.

Increased protective measures including stepped up right-of-way patrols and public education efforts have attempted to reduce the vandalism that plagues us and utilities everywhere. But it can't stop it all — not by any means.

Public awareness of the problems and quick notification to local authorities by members of the public who suspect or see evidence of vandalism can also act as a deterrent.

There's plenty of incentive to the public besides good citizenship. Vandalism affects everyone's pocketbook, and helping curb it can save money for all ratepayers.

Dispatcher Training

Regardless of all protective measures that can be economically taken, things go wrong. Dispatcher training, therefore, becomes an essential ingredient to assure safe and reliable operation of the power system.

Over the years, BPA's training programs have not been as strong on dispatcher training as we now feel is necessary — especially in light of the Three-Mile Island accident and lesser incidents.

Although we have provided refresher training for substation operators, no formal refresher training program exists for dispatchers.

So, we are now developing a dispatcher training program to reacquaint dispatchers with all their previous training as well as to acquaint them with a variety of new situations and problems they might be expected to handle.

Other utilities are doing the same thing. Some are purchasing computer simulators, while others are holding back on spending significant amounts of money until their full training needs are developed.

BPA is proceeding cautiously, concentrating initially on refresher training in the basic skills. But we also are working closely with the WSCC in its development of a training program that would be available to the 47 member systems of WSCC. This training would be utilized to supplement BPA in-house training. BPA also is exploring with the Electric Power Research Institute (EPRI) and WSCC the full range of requirements to be built into a power system simulator. Further dispatcher training decisions will be forthcoming in 1980.

ENGINEERING & CONSTRUCTION

Construction crew is silhouetted high atop a tower while inset illustrations show cross-section view of conductor cable used for 34.5 kV underwater transmission and 500-kV and 1100-kV overhead transmission lines.

Loss Savings

Not all of the electrical energy fed into a power system at the generating end comes out the other end when the energy is delivered to customers. Some of the energy is lost along the way.

Losses are a function of several factors. The most important are voltage, distance, line loading and conductor resistance. Most of the energy lost is converted to heat by resistance in the conductors and transformers.

Years ago BPA designers had very few alternatives to consider in reducing losses because electricity was relatively cheap then. But today, with inflation and soaring costs for new generation, the value of lost energy has risen sharply. Electrical losses on BPA's system now amount to about 550 mW on peak, and 2.7 billion kWh a year. The value of this energy in 1979 was about $8 million, based on an average price of 3 mills per kWh. If the power were valued at today's replacement costs, the cost of losses would be approximately 10 times as much.

Losses can be reduced by going to higher voltages, and this has been the trend as technology developed. It has been estimated, for example, that the new 1100-kV lines — the first use of which is projected for the late 1980s — will cut electrical losses per unit of power transmitted by about half, as compared with 500-kV. The value of electrical losses may hasten the day when the first commercial 1100-kV line is built.

Another way to reduce losses is to reconductor lines with larger conductors and install equipment with higher efficiencies. BPA is identifying facilities on its system that can be altered or rebuilt to cut losses when it would pay to do so. For example, studies have shown that three projects involving conductor replacement, system reconfiguration and conversion to higher operating voltage could save approximately 19.5 mW on peak. For every dollar spent on these projects, the value of loss savings would be $8.10, based on a replacement value of 23 to 27 mills per kWh.

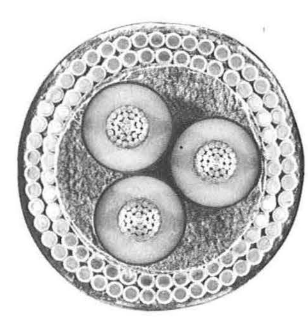
These projects are going forward. Projects now being pursued by BPA are expected to reduce our electrical losses by 5 percent, or $3 million a year, assuming current replacement costs for energy.

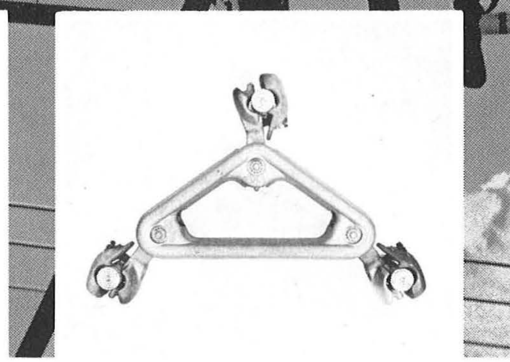
The potential for further savings is great. Energy losses on the BPA system consume about 3 percent of the total energy transmitted. This will amount to about 3 billion kWh in 1981 and more than 6 billion kWh in 1995.

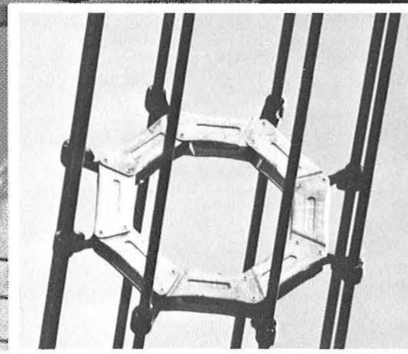
As the value of electricity continues to rise, BPA will continue to seek out places where it will pay to convert lines to higher voltages, reconductor existing lines or change out existing less efficient equipment.

Fourth Generation 500-kV

In years past, when a new line design for a higher voltage was adopted, the first lines were built before the development work was completed. The initial designs at the new voltage were unusually conservative. As development work progressed, designs were refined. Improvements and substantial savings resulted. This was the case with 500 kV.







The first 500-kV line on the BPA system was energized in 1967. In 1979, we completed the fourth generation of designs for single and double-circuit 500-kV lines. The total cost of a fourth generation 500-kV single circuit line is 10 percent less than the cost of a third generation line; the cost of a double-circuit line is 17 percent less.

Fourth generation towers are better designed and weigh less. Electrical clearances have been reduced in accordance with the latest national electric safety codes.

About half of the savings for single-circuit lines and two-thirds of the savings for double-circuit lines can be attributed to improved structural and mechanical designs.

This can result in a reduction of 10 feet in rights-of-way — from 115 feet to 105 feet for single-circuit lines and from 135 feet to 125 feet for double-circuit lines.

In terms of total cost per mile, the new designs resulted in savings of $40,000 per mile for single-circuit lines and $130,000 per mile for double-circuit lines.

Fourth generation lines — with the new towers — are already beginning to appear on the system. It takes a sharp eye to distinguish them from older types.

Customer Service Substations

BPA in 1977 set out to reduce the cost of its customer service substations by 30 percent. We also sought to design these substations so they could be built from the ground up in less than 30 days using items available off-the-shelf from manufacturers.

The designers were also asked to come up with a standard plan that would use less land. The idea was to lessen environmental impacts by making the substations smaller and thereby less conspicuous.

It seemed like a big order at the time, but BPA's designers and construction forces achieved all of these goals in less than 2 years.

The proof of the pudding came last summer when BPA workers assembled the new lower profile East Ellensburg Substation in less than 15 days using 60 percent less land — for a third less money.

East Ellensburg cost 27.5 percent less — 33.3 percent less when the cost was adjusted for inflation — than Hatton Substation, the last of the old type. Hatton was built in the Columbia Basin in 1977.

We saved about 22 percent by purchasing transformers standard to the industry. On-site time was reduced by prefabricating some of the substation's components in our shops and assembling them on the site.

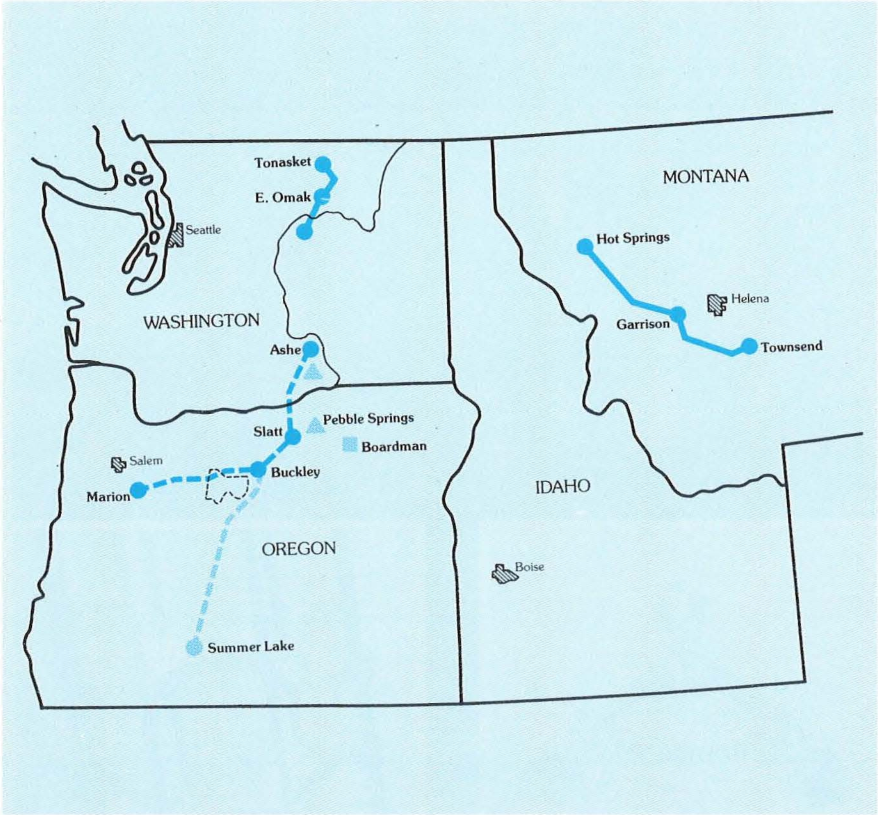
East Ellensburg Substation taps a 115-kV line and delivers power to the City of Ellensburg at 12.5-kV.

We plan to refine the designs and construction techniques used for East Ellensburg and employ them for future customer substations.

Gas-insulated Terminal

A 500-kV terminal insulated with compressed sulfur hexafluoride gas has been installed at Pearl Substation. We installed the terminal to broaden our experience with newly developed gas-insulated equipment that can drastically reduce the space required for high-voltage substation facilities.

If the terminal proves out, we



Map at left shows routes of four major line construction projects, while chart on opposite page shows how line losses are reduced the higher the transmission voltage.

may then consider whether to install gas-insulated substations at locations where space is at a premium. The terminal at Pearl consists of an isolating disconnect switch and a power circuit breaker placed to protect a 500/230-kV transformer bank. The terminal was energized in the fall of 1979.

System Totals

During FY 1979, we added 160 circuit miles of transmission lines and one substation to our system. The circuit mileage included 90 miles built to operate at 500-kV, 60 miles at 230-kV, 7 miles at 138-kV, and 3 miles at 115-kV or lower voltages. Transformer capacity added totaled 2,145,308 kVa.

These additions brought system totals as of September 30 to 12,615 circuit miles and 347 substations. Of this, 265 miles are 800-kV direct current. The totals for the other lines are 2,980 circuit miles of 500-kV, 709 miles of 345-kV, 1,450 miles of 287-kV, 3,435 miles of 230-kV, 46 miles of 138-kV, and 3,730 miles of 115-kV or lower voltage lines. Transformer capacity for the system totaled 52,723,721 kVa.

Projects Underway

Projects presently under construction will add another 1,481 circuit miles of line and 15 substations to the system. Of this, 1,213 miles are 500-kV, 239 miles 230-kV, and 29 miles 115-kV or lower voltages. The transformer capacity being added totals 8,005,100 kVa.

The Ashe-Slatt Project

One of the major projects underway is the construction of a double-circuit 500-kV line that runs 71 miles from Ashe Substation on the Hanford Reservation to Slatt Substation near Arlington, Oregon. Most of this line has been built. Construction of a 22-mile section and a crossing of the Columbia River at Crow Butte Island is now underway after delays.

The Corps of Engineers delayed issuing a permit to cross the Columbia because the U.S. Fish and Wildlife Service believes the line may impact part of the Umatilla Waterfowl Refuge on the eastern half of the island.

BPA agreed to fund a study of the line's impact on the refuge. We also agreed to pay the costs of developing more land for the refuge if impacts on existing refuge lands are shown by the study to be significant. These costs could approach $1 million.

The Slatt-Marion Project

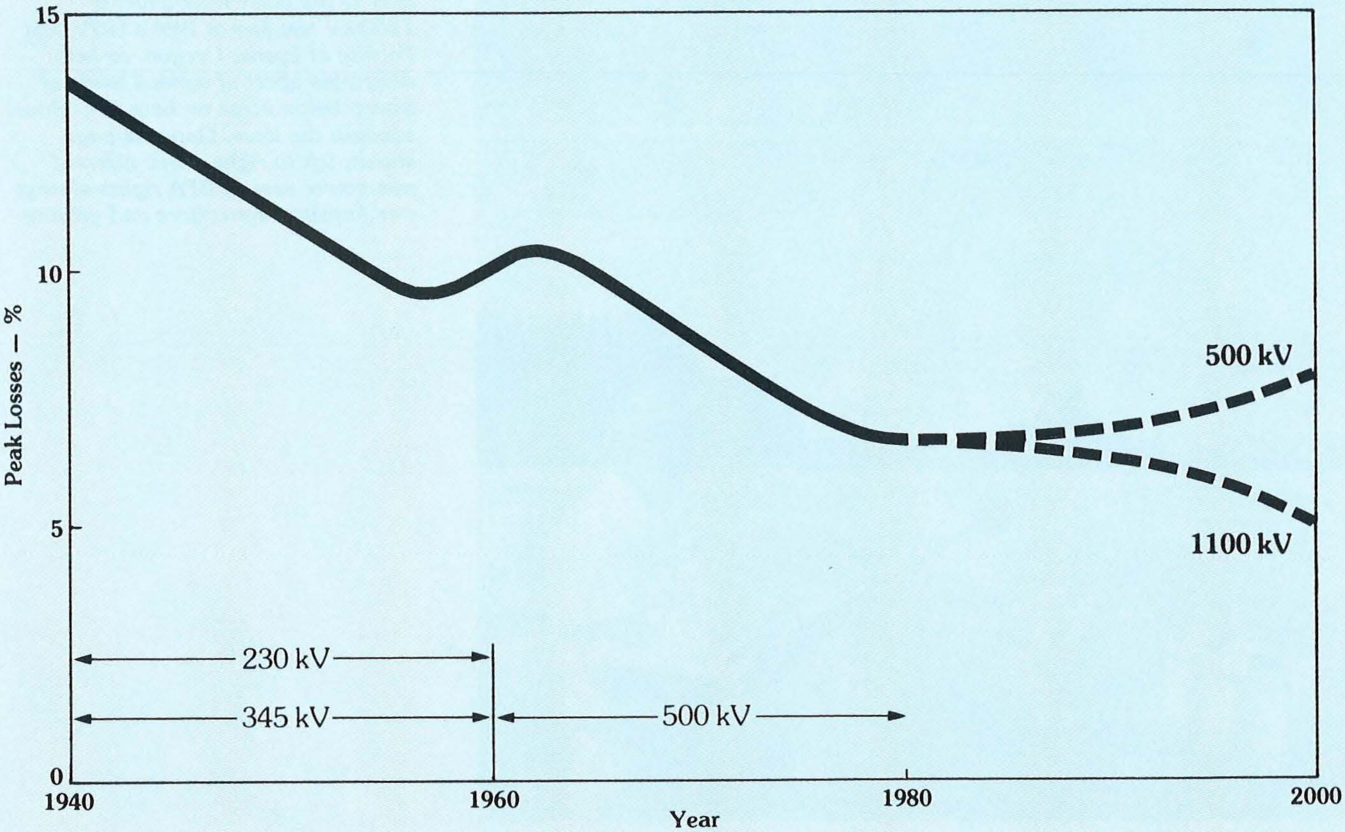
The double-circuit 500-kV line from Ashe Substation continues on from Arlington and runs an additional 155 miles to the Willamette Valley. It ends at Marion Substation near Salem. The Ashe-Slatt-Marion circuits will strengthen transmission to western Oregon. The present schedule calls for the line to be energized in 1980.

The Ashe-Slatt-Marion circuits are high capacity and will reduce the cost of electrical losses on the system by about $1 million a year. These circuits are among our "fourth generation" designs.

Buckley-Summer Lake

The Buckley-Summer Lake line has been included in our 1981 budget. It is to run 156 miles from Buckley Substation near Maupin,

System Losses



Oregon, south to a new substation near Summer Lake. The line will connect there with Pacific Power & Light Company's Midpoint-Malin line that extends from southern Idaho to southwest Oregon. PP&L's line is to be energized in the fall of 1981 and BPA's line in the fall of 1982. The Ashe-Marion circuits also will be looped into Buckley.

The Buckley-Summer Lake project will reinforce service to southwestern Oregon. It will also increase the reliability of the Pacific Northwest-Pacific Southwest Intertie, support growing loads in the Bend area, back up the Midpoint-Malin line, reduce electrical losses, and add capacity to serve BPA's loads in southern Idaho.

Contractual agreements with PP&L will allow BPA to schedule as much as 500 megawatts on the company's Summer Lake-Malin line. PP&L will be able to schedule 240 megawatts on BPA's Buckley-Summer Lake line. These amounts will be boosted to 1,000 and 340 megawatts, respectively, when Buckley Substation is expanded to loop in the existing 500-kV intertie lines.

Montana Transmission

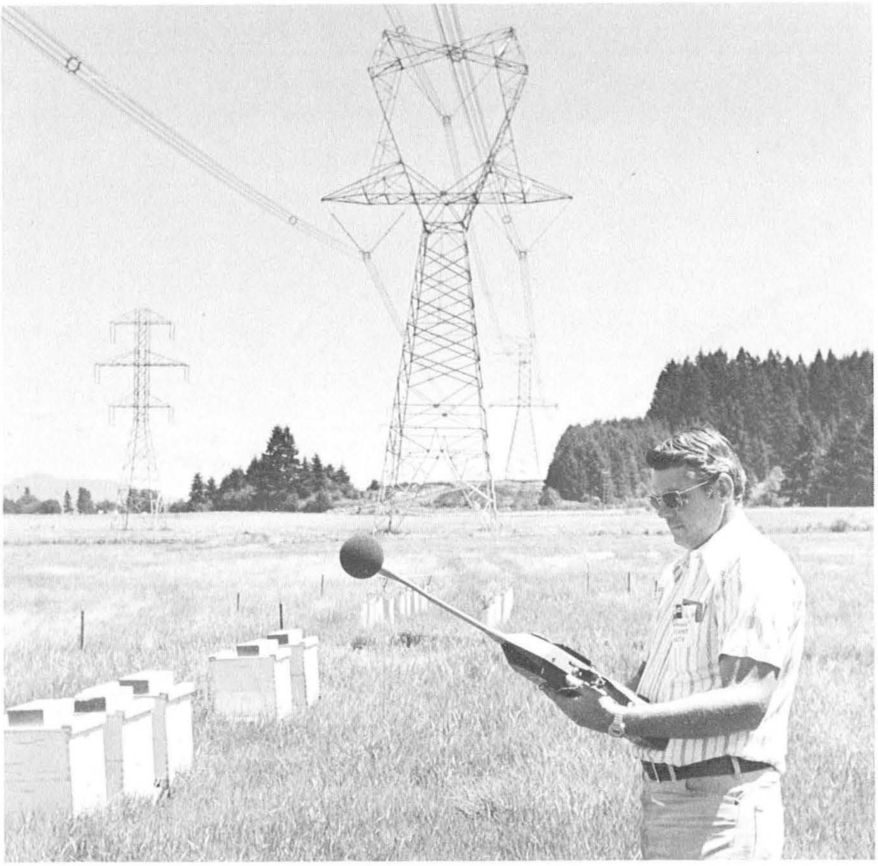
A plan has been engineered to transmit power to Northwest load centers from two generating units being constructed at Colstrip in eastern Montana. The final environmental impact statement for the transmission project was filed in July. Colstrip units 3 and 4 — each with generating capacity of 700 mW — are tentatively scheduled to come on line in late 1983 and 1984. They are being financed by a group of five privately owned Northwest utilities. Sixty percent of the power produced by Colstrip units 3 and 4 and 50 percent of Colstrip units 1 and 2 is to go to West Group utilities of the Northwest Power Pool. Much of this power must be transmitted almost 1000 miles to the Puget Sound and Willamette Valley load centers.

Under the plan, the Montana Power Company will construct the facilities from the plant to Townsend, Montana. BPA will construct the line from there west to Garrison. At Garrison the line will take one of two routes that are still being studied. The final route is to be selected soon. One route under consideration follows an existing right-of-way across the Flathead Indian Reservation. One side of this right-of-way is not being used. It is wide enough to carry a double-circuit 500-kV line. BPA's right to construct such a line on the right-of-way is disputed by the Salish and Kootenai tribes.

Okanogan Area Service

During the year, BPA and the Colville Confederated Tribes reached agreement on the route of a double-circuit 230-kV transmission line that will serve the Okanogan area. The first segment of the line will extend 34 miles from Chief Joseph Dam to East Omak Substation. All but 5 miles of this segment cross the Colville Reservation. The second segment consists of 21 miles of line from East Omak to Tonasket Substation. Surveying, the first step in the construction process, began late in the fall of 1979. The line is to be energized in October 1981.

The Tribal Council granted BPA perpetual easements for the existing



BPA Engineer Alfred L. (Lyn) Gabriel checks the noise level under a 1200-kV test line at BPA's UHV Test Facility at Lyons, Oregon, to help determine effect of various levels of transmission noise on bees in beehives beneath the lines. Opposite page shows, left to right, three different non-power uses of BPA rights-of-way: tree farming, agriculture and grazing.

Brewster-Okanogan and Okanogan-Omak lines, as well as for a proposed line from Grand Coulee Dam to the Keller area desired by the Tribes.

The new 230-kV line will improve the reliability of service to the Okanogan Valley and much of the Colville Reservation. It was needed because not all of the loads in the valley could have been served if one of the two 115-kV lines that now convey power to the valley were to fail during peak load periods.

Underground Cable

BPA was given a new and unusual challenge for the routing of a 230-kV station service line that needed to cross the 500-kV transmission line from the Washington Public Power Supply System's WMP-2 generating plant. For reliability reasons, the NRC required this 230-kV circuit to be underground. Although BPA has contracted installation of marine cables and a section of compressed gas insulated 500-kV cable, this was the first time for BPA to design and install with its own forces a cable operating at transmission voltage levels.

Three 5,000 MCM 230-kV paper insulated low pressure oil filled cables and terminations were installed at Ashe Substation by BPA's Substation Construction Force Account personnel. The three cables were placed in a single trench. The total length of the circuit was 1,450 feet and is currently one of the largest cables of its size and capacity in the world.

Revenue Metering

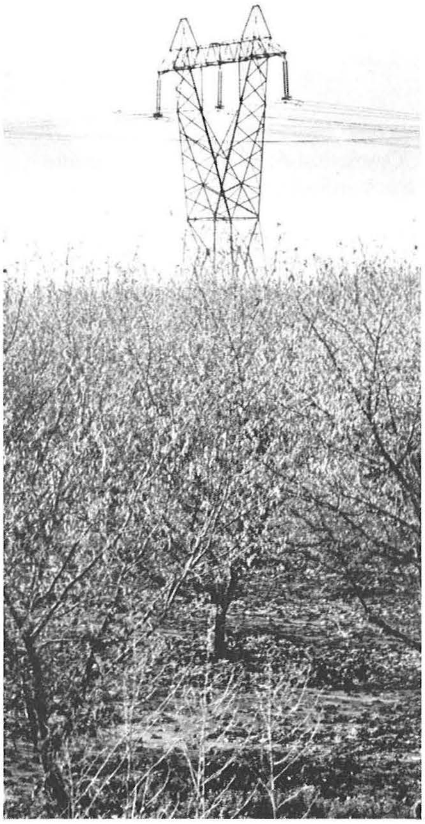
Three divisions of BPA have begun work on a specific plan to improve our revenue metering system. We are proposing to use solid-state revenue meters on a rather large scale beginning in 1982.

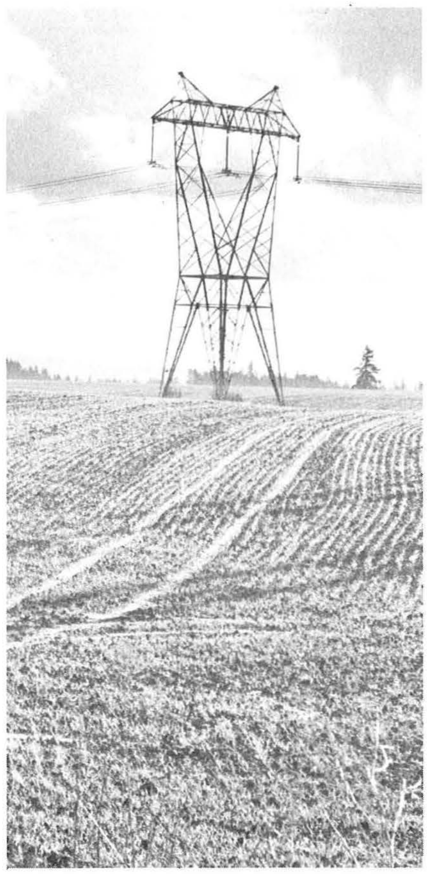
Revenue meters measure the amount of power a customer uses. The meters are used in the billing process and are sometimes referred to as the cash registers of the system.

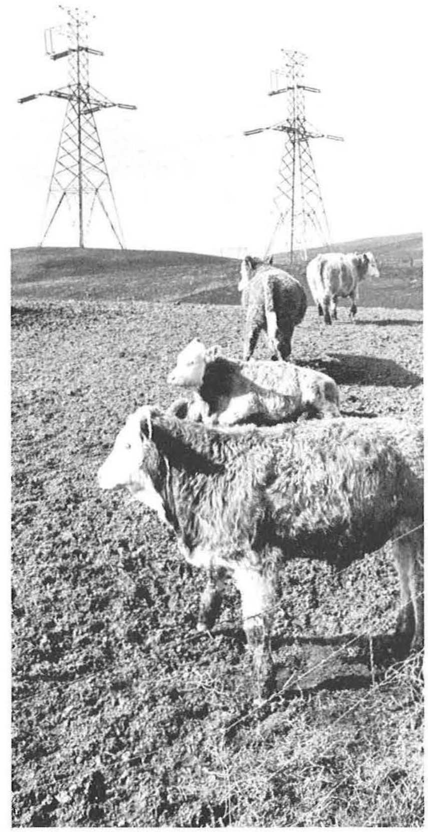
Much of the work in the billing process is still done by hand. It is this manual work that the three divisions — Engineering and Construction, Operation and Maintenance, and Power Management — are attempting to reduce. The new system is expected to increase metering accuracy, decrease the space required for equipment, lower installation and maintenance costs, and increase our automatic billing capability.

Remodeling Project

A large, bare, one-story concrete shell — the south wing of the Ampere Building at Ross Substation — has been completely remodeled to turn 60 percent of the total space in the wing — some 43,600 square feet in all — into modern laboratories. The other 40 percent of the remodeled space is occupied by an automotive maintenance shop. The south wing formerly housed carpenter, automotive, and small engine repair shops. The chemical laboratory and the instrumentation and standards laboratory have been moved from a cavernous, creaky, wood-frame building of World War II vintage into the remodeled space.







Supply Operations

During 1979 a major consolidation of supply support activities was completed. The 100,000 square foot warehouse on the Ross Complex, already full to capacity was extensively remodeled to absorb the $1.5 million inventory of Tools and Work Equipment previously stored in a number of small facilities at Ross. High density, narrow-aisle storage racks were installed, which increased storage capacity 40 percent. Tools were integrated with general construction and maintenance stock and purchased according to activity levels. New self-storing, electric order picking equipment now operates quickly and safely in narrow aisles. Physical consolidation of materials storage was accompanied by reorganization and relocations which combined similar transportation and other support functions. Transportation and Field Purchasing were relocated to newly prepared offices in the warehouse, a Flammable Storage Building was installed, and Tool and Small Engine Repair facilities were installed in the Utilization and Disposal Building. Through these consolidations and relocations a more integrated and efficient supply support organization has emerged, with savings in manpower, equipment utilization, energy consumption, and occupied storage space.

Canadian-U.S. Studies

A study group has found that substantial amounts of surplus nonfirm energy will be available in both the near and long-term for exchanges among utilities in the Pacific Northwest, British Columbia, and Alberta. The study group consists of representatives of BPA, British Columbia Hydro and Power Authority, and the Alberta Interconnected Systems.

Much of this power could be sent to market over existing transmission networks and interconnections. But more lines would have to be built to transmit all of it to market.

The study group came as a follow-up to an earlier study in which BPA represented WSCC. The U.S. and Canadian governments identified for the WSCC area past and prospective power transactions and transmission constraints.

The study group looked at the year 1984-85 as representative of the near term when only existing facilities would be available for use. They also studied the year 1989-90 as representative of a year for the long-term — a year for which additional transmission capacity could be constructed.

The surplus energy in Alberta is mostly off-peak energy from coal-fired generating plants. The rest is hydro energy.

The study group also reported that some energy is available to displace higher cost energy from oil-fired plants. Its findings are presented in two reports. One was written earlier and the other this past year. The study did not include gas-fired generation in Alberta because of Canadian export restrictions.

RIVER OF MANY USES

"Operation Fish Run" photo shows truck movement of fingerlings past a Columbia River dam, while three inset photos illustrate irrigation, navigation and recreational uses of the river. Irrigation photo shows Administrator Munro discussing pump testing program with farmer. Navigation photo shows the sternwheeler S.S. Portland passing through the locks at Lower Monumental Dam. Recreation photo shows beach scene behind John Day Dam.

Beauty . . .

The beauty of the Columbia River is that it serves so many purposes:

- It still produces more than 80 percent of the electricity consumed in the region.
- It provides water for most of the 8 million irrigated acres in the region.
- It is the spawning grounds for a great anadronomous fishery.
- It provides navigation all the way to Lewiston.
- It provides boating and other recreation for local residents and serves as a tourist lure.
- It provides water for municipal and industrial uses.

Many of the present benefits result from upstream storage. The natural flow of the Columbia varies widely from season to season and year to year. More reservoirs on the headwater tributaries could increase these benefits, and the Corps of Engineers is studying a number of potential sites.

. . . And the Beast

The trouble with the Columbia River is that it no longer has sufficient capacity to meet all the demands on it.

And that causes a lot of differences of opinion.

It wasn't all that long ago that people didn't have to choose between fish and power, or irrigation and power, or other competing uses. There was enough to go around for all uses.

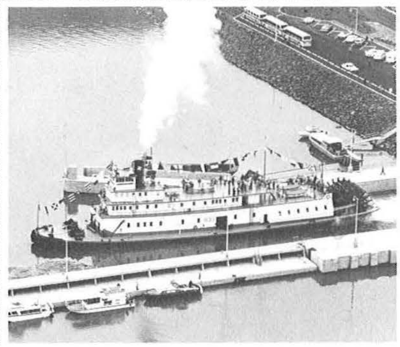
As the Tri-City Herald editorialized September 24, 1979: "It was considered a joke in 1952 when former Gov. Len Jordan told a congressional committee that it was Idaho's goal to dry up the Snake River at Hells Canyon by using all of the water for irrigation. Nobody is laughing now. Idaho Power Co. is in federal district court in Boise suing Idaho and several state agencies. It charges that irrigators upstream from its power dams are diverting water to which the company has a priority right."

Well, this Annual Report is no place to attempt to resolve that question of basic rights. It is a place to observe, however, that for every gallon of water diverted upstream a half gallon on average is lost forever for downstream power production. The power producing capability of this water is lost over and over at each power dam below the point of diversion. In the case of water taken out of the Snake River for irrigation at the Minidoka Reservoir, it is lost 18 times over — at 14 dams on the Snake and four downstream on the lower Columbia.

BPA has computed that the water used to irrigate 11 million acres would produce 1000 megawatts of power. That doesn't take into account the "double whammy" effect of having to use large amounts of electricity to pump a lot of the water that goes into irrigation.

Nor does it mean that the jobs and food that irrigation produces are not worth the loss of power. The people, through the Congress, have repeatedly found otherwise. But it does illustrate that the Columbia River isn't as big as it used to be in terms of satisfying all the competing demands.

Power needs now take a back seat not only to irrigation, but also to fish protection. And power operations now take into account recre-



ation — even the regatta races above McNary Dam — and navigation and all the other multiple uses. It's a matter of trade-offsand, to some extent, horsetrading.

Power and Fish

Some of the more difficult trade-offs involve power and fish, and properly so. Fish pump millions of dollars into the economy of the Northwest states — $132 million per year each of the past three years, according to the National Marine Fisheries Service.

Over the years, extensive fish passage, protection and enhancement facilities have been constructed either as an integral part of or in conjunction with power producing dams. The share of capital costs allocated to power totals approximately $200 million. This translates into annual costs of about $15 million which must be recovered through BPA revenues.

In addition, BPA has entered into a Memorandum of Understanding with the four Confederated Tribes and the Pacific Northwest Regional Commission to assure a coordinated and comprehensive approach to solving fisheries problems.

A significant part of this program will include the $1.5 million in contracts we were ready at the end of 1979 to award to State and Federal agencies for 10 studies and projects to be carried out in 1980 to help improve salmon and steelhead stocks in the Columbia and its tributaries.

Summing Up

Historically, multipurpose river development in the Northwest began with only three purposes: navigation, irrigation and power. Flood control was added in 1950.

Recreation is seldom authorized by Congress as a purpose in our region, but the projects are nevertheless operated for that benefit.

Fishery protection is not a stated purpose of multipurpose development, but rather a mitigation requirement, as are wildlife aspects in the Lower Snake River area.

Congress also has set aside wild and scenic rivers, wilderness areas and recreation areas, of course, where no dams may be built.

Over the past 40 years, more than 1¾ billion dollars of Federal Columbia River development funds have gone into multiple purposes other than power — for navigation, irrigation, flood control, recreation and fish and wildlife.

Power pays for some 83 percent of this total Federal investment. Multipurpose development, by sharing joint costs, enhances feasibility of any purpose, including power. Many other purposes could not stand on their own feet, and the fact that dams accomplish purposes besides power has made some projects feasible that wouldn't otherwise be. One hand washes the other.

FINANCIAL SECTION

The Financial Year

Federal Columbia River Power System (FCRPS) gross operating revenues totalled $296.6 million for FY 1979, a decrease of $37.4 million (11 percent) compared to FY 1978.

The poor revenue performance was due primarily to low streamflows during much of the year, limiting the amount of energy which could be generated by the hydro projects. This resulted in restriction of service to industrial customers served directly by BPA. The low streamflows also left less secondary energy available for sales to the privately-owned utilities. Sales to industries and privately-owned utilities declined by $24.3 million and $20.3 million, respectively(30 percent in each case), from the FY 1978 level.

However, we were able to meet the 8 percent increase in load growth of preference customers, who are entitled to first call on all available firm energy. Sales to these customers increased by $10.4 million, to a new record high of $146.8 million.

On the expense side, continued inflationary pressures and record high interest rates pushed total operation and maintenance expense up by $13.1 million (12 percent) and net interest expense up by $25.8 million (18 percent). Purchase and exchange power expense declined, however, by $25.9 million (51 percent).

Rate Changes End Downslide

Decreased revenues combined with increased expenses produced a record deficit of $69.9 million for the FCRPS on a cost accounting basis. This was the third year in succession that expenses exceeded revenues, due primarily to (1) inflation, high interest rates and system expansion, and (2) BPA's inability to increase power rates during the 5-year period from December 20, 1974 to December 20, 1979; a provision in our power sales contracts heretofore restricted the frequency of rate adjustments to 5-year intervals.

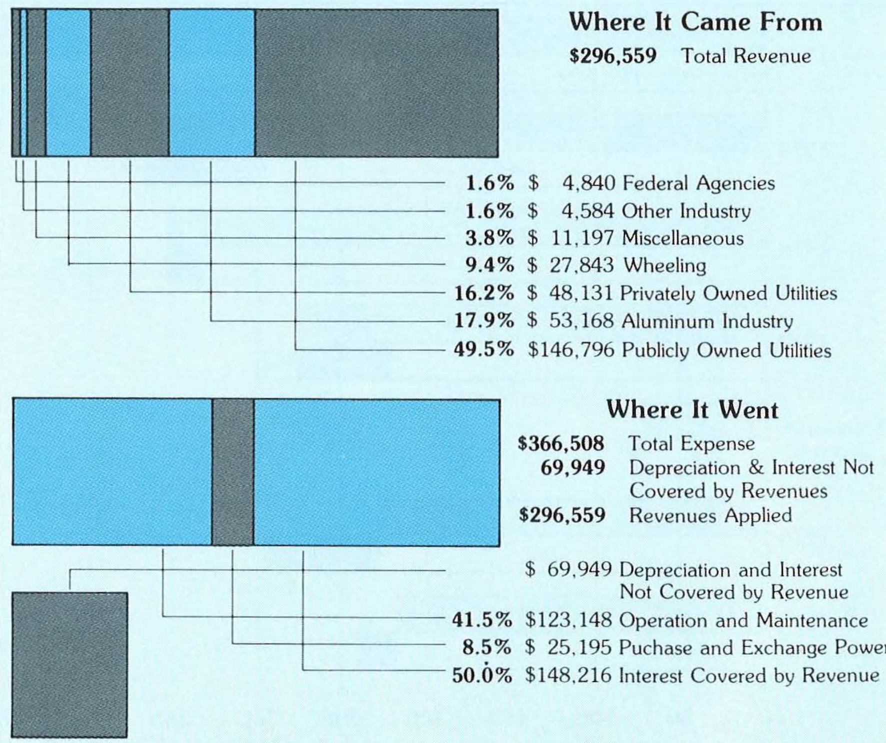
But the financial downslide has now been reversed. The 88-percent power rate increase approved as of December 20, 1979, plus a customer agreement to more frequent future rate adjustments, is expected to put the FCRPS consistently "in the black" in future years. Rate changes now can be implemented each July 1 commencing in 1981.

In spite of the recent deficits, on a cumulative basis the FCRPS still ended FY 1979 with net revenues (revenues in excess of expenses) of $242.1 million due to many prior years of surplus revenues. Recent deficits, however, have over the past three years reduced cumulative net revenues by $143 million below their alltime high of $385 million.

Basis for Financial Reporting

BPA prepares financial statements for the FCRPS on a cost accounting basis to assess its financial condition from the viewpoint of a commercial enterprise. The financial statements are independently audited by the firm of Coopers & Lybrand, certified public accountants, in accordance with generally accepted auditing standards. The complete financial statements with the auditor's opinion appear on pages 43 through 53. A

Source and Dispositon of Revenue Dollar
Fiscal Year 1979 (In Thousands)



graphic portrayal of financial results on this basis and a forecast for FY's 1980 and 1981 appear on page 34.

Power rates, however, are not set to match costs as determined on the cost accounting basis. Rates are based upon what is called the repayment basis. This report also includes the FCRPS repayment study (table 5, pages 40 and 41, and graph on page 35) which was used to determine the 88 percent revenue increase.

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 measure two different things, that is, current financial results in the cost-accounting statements and future financial requirements in the repayment study.

More Differences

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 (see page 42), however, requires that the investment in all power facilities be fully repaid within 50 years following each facility being placed in service. The level of revenue required to meet the repayment requirement, therefore, is higher than needed to cover costs on the cost accounting basis. Consequently, now that power rates have been increased to meet the current repayment requirement, and BPA now has the right to adjust rates at more timely intervals, the prospect is that the FCRPS should normally produce net revenues rather than deficits on the cost accounting basis. There could be exceptions to this, however, should approval of future rate increases be denied, or if low streamflows limit revenues.

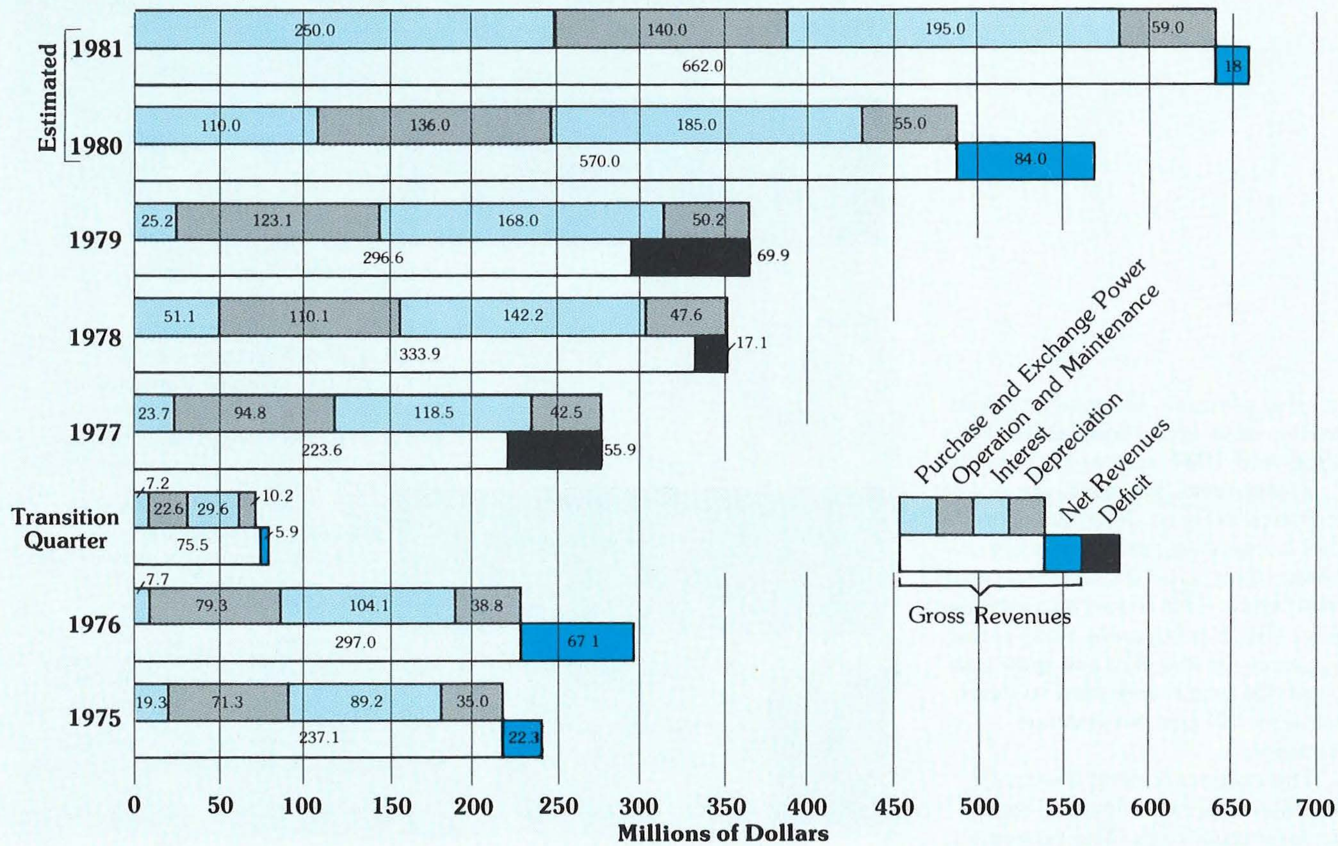
Another noteworthy difference between the cost accounting statements and the repayment study is that the latter reflects certain costs, such as purchased power, on a cash-payment basis. The cost accounting statements record such costs on the accrual basis. This results in different amounts being shown 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 capability of the WPPSS nuclear plants commit BPA to paying WPPSS beginning on specified dates even though the plants have not commenced operation. For example, BPA's payment for its 100-percent share of the capability of the WPPSS Nuclear Project No. 2 commenced in January 1977 even though that plant, due to construction delays, presently is not expected to be in operation until 1981. In this situation, the repayment study shows the amount of actual cash payments, but the cost accounting statements treat this item as a deferred expense until the plant starts operating. However, with the planned full recovery of such payments with the increased power rates effective December 20, 1979, additional WPPSS payments will be charged to expense on a current basis for cost-accounting purposes.

Repayment Issues

During the course of development of the power rate increase proposal, a number of issues were raised by BPA customers and other interested parties concerning BPA's application of the repayment criteria. A central point of many questions concerned what future costs should be included in the repayment study.

The greatest interest was focused on the costs of the WPPSS nuclear plants currently under construction. BPA is committed by contract to paying its share of these costs commencing on fixed dates regardless of

Revenue and Expense Trend



whether the plants are completed or operating. Due to construction delays, the fixed dates come several years ahead of the dates the plants are now expected to be operational.

BPA in its preliminary rate proposal assumed that it must include in the repayment study all payments which it is committed to make to WPPSS. Many customers argued, however, that generally accepted rate-making principles precluded including costs in a rate level for facilities which will not be in service during the time the rates will be in effect. (In this case, it is assumed the new BPA rates will be in effect from December 20, 1979, through June 30, 1981.)

It was proposed that WPPSS issue additional bonds to finance the costs at issue. These costs are primarily interest on the WPPSS construction bonds, plus some amortization of shorter-term WPPSS bonds. This proposal for BPA to pay less now but more later required the unanimous approval of all 104 participants in the WPPSS plants, but two participants did not concur.

As an alternative solution, BPA agreed to include in the repayment study only the fixed costs (primarily for interest and amortization of the WPPSS bonds) for WPPSS plants No. 1 and 2 which it is irrevocably committed to paying. Future costs for operation and maintenance of the WPPSS plants as well as the revenues that would be produced by the plants were omitted from the repayment study.

Another major issue concerned future Federal power projects which are authorized by Congress for construction but which will not be completed and in service during the rate period. BPA had traditionally interpreted Public Law 89-448, which authorized construction of the Third Power Plant at Grand Coulee Dam in 1966, as requiring the inclusion of all authorized Federal projects in the repayment study regardless of when they would be placed in service. The customers objected that this would be contrary to generally accepted rate-making principles.

The BPA General Counsel, therefore, re-examined PL 89-448 and concluded that it does, in fact, require the inclusion of all authorized projects in an annual financial report to the President and the Congress, but that this requirement was not applicable to rate setting. Consequently, the General Counsel concluded that future projects should be excluded from the repayment study prepared to determine the new revenue level.

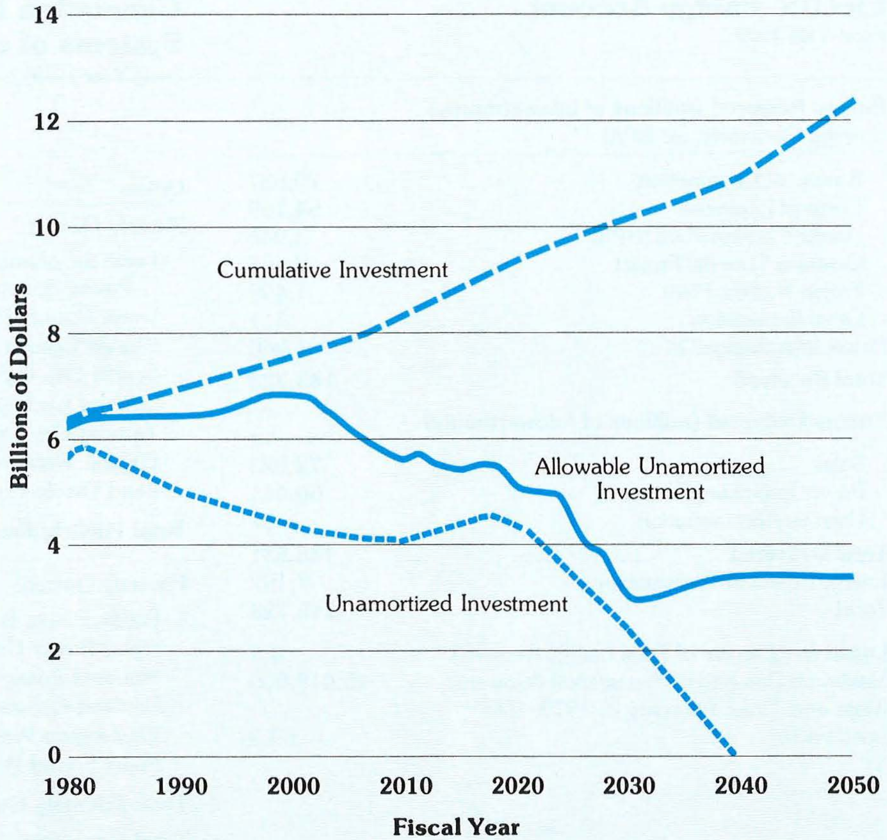
Therefore, in the final repayment study that determined the need for the 88-percent revenue increase, the costs and revenues associated with all Federal power facilities which are not scheduled to be in service by July 1, 1981, were excluded. The costs of those projects will be included in repayment studies which will be prepared for future rate adjustments, the next of which is planned for implementation as of July 1, 1981.

Reasons for Rate Increase

Customers and the general public have shown keen interest in the reasons for the large BPA rate increase. Many factors contributed to the need for such a large increase. The most prominent factors were:

1. It had been 5 years since

Federal Columbia River Power System
Repayment Study Chart
Fiscal Year 1979



BPA's previous rate increase. That 5-year period was characterized by a generally high rate of inflation and high interest rates which pushed up both operating costs and the cost of new facilities.

2. Cost escalation at the Federal hydroelectric projects and the BPA transmission system accounts for about one-third of the 88-percent increase. Had this been the only factor, the rate increase would have been on the order of 30 percent. When translated to a compound annual rate of escalation over the 5-year period, the increase amounts to only about 5.5 percent per year. That compares favorably with the general rate of inflation during that period.
3. About two-thirds of the 88 percent increase is attributable to two major factors. The first is cost escalation at the Trojan Nuclear Plant and the WPPSS Nuclear Plant No. 2 since BPA's last rate adjustment in December 1974. As included in the repayment study, the cost to BPA of its 30-percent share of the Trojan Plant increased by approximately 130 percent during the five-year period while the cost increase to BPA of its 100-percent share of WPPSS Plant No. 2 (adjusted to the fixed cost only basis) is approaching 250 percent. The second major factor was inclusion of the cost of WPPSS Plant No. 1 in the repayment study for the first time. BPA's payments to WPPSS for Plant No. 1 commence as of January 1980.

The cost to BPA for its acquisition of nuclear power from Trojan and WPPSS, therefore, is the largest single factor in the 88 percent rate increase. The nuclear plant costs have escalated at a much faster rate than other power system costs due to the unique problems that have afflicted nuclear plant construction and operation. These problems include revised regulatory requirements, design changes, increased security requirements, technical difficulties, labor disputes, poor contractor performance, etc.

Repayment Study

The repayment study included in this report (Table 5, page 40) demonstrates that, together with an anticipated increase in transmission ("wheeling") rates, the rate increase effectuated December 20, 1979 will be sufficient to meet all of the repayment criteria under the conditions assumed in the study. It should be noted, however, that at the time the study was prepared, actual FY 1979 results were not yet known and FY 1979 revenues and costs were included in the study on an estimated basis. These estimates are based on the presumption of average conditions with the knowledge that some years will turn out to be above average and others below average. Over the long run, the above-average years tend to offset the below-average years. As it turned out, FY 1979 was a below-average year due to poor streamflows, and actual revenues fell \$38.6 million below the estimate, while O&M expense exceeded the estimate by \$4.7 million. However, these variations, which are shown on the "adjustments" line on the repayment table, can be expected to be offset at some time in the future by an above-average revenue year. If this should not occur, the effect will be taken into account in future rate adjustments.

To comply with the requirement of Public Law 89-448 for an annual report to the President and the Congress which includes all authorized Federal power facilities, a note to the repayment study (page 42) lists the authorized projects not specifically included in the repayment study, together with pertinent data thereon.

Table 1

Electric Energy Account

Fiscal Year 1979

Energy Received (millions of kilowatthours) (Energy Generated for BPA)	
Bureau of Reclamation	20,637
Corps of Engineers	54,769
Hanford Steam Plant (NPR)	3,946
Centralia Thermal Project	2,601
Trojan Nuclear Plant	1,499
Other Generation	311
Power Interchanged In	61,960
Total Received	**145,723**
Energy Delivered (millions of kilowatthours)	
Sales	72,023
Power Interchanged Out	66,441
Used by Administration	67
Total Delivered	**138,531**
Energy Losses in Transmission	7,192
Total	**145,723**
Losses as a Percent of Total Energy Received	4.9
Maximum Demand on Generation (kilowatts)	15,419,000
(Date and Time) February 2, 1979, 0900	
Load Factor	69.3

Table 2

Generation by the Principal Electric Utility Systems of the Pacific Northwest

Fiscal Year 1979[1]

Utility	Kilowatt-hours (Billions)	Of Total Generation (Percent)
Publicly Owned:		
Federal Columbia River Power System[2]	83.8	53.3
Grant County PUD	10.1	6.4
Chelan County PUD	8.1	5.2
Seattle City Light	5.2	3.3
Douglas County PUD	3.9	2.5
Tacoma City Light	2.0	1.3
Eugene Water & Elec. Board	0.6	0.4
Pend Oreille County PUD	0.3	0.2
Total Publicly Owned:	**114.0**	**72.6**
Privately Owned:		
Pacific Power & Light Co.	12.6	8.0
Idaho Power Company	11.1	7.1
Montana Power Company	7.1	4.5
Portland General Electric Co.	6.0	3.8
Washington Water Power Co.	4.6	2.9
Puget Sound Power & Light Co.	1.8	1.1
Total Privately Owned:	**43.2**	**27.4**
Total Generation:	**157.2**	**100.0**

[1] Generation shown is for members of the Northwest Power Pool plus Pend Oreille County PUD and Washington 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 beacuse their service areas lie outside the Pacific Northwest.

[2] Includes generation from the Washington Public Power Supply System's Hanford steamplant (NPR), Okanogan PUD's share of Wells, the municipalities of Forest Grove, McMinnville, and Milton-Freewater share of Priest Rapids and Wanapum and the Federal share of the Centralia steamplant and the Trojan Nuclear Plant.

Table 3
Federal Columbia River Power System

General Specifications of Projects Existing, Under Construction, Authorized or Licensed, and Potential

Nameplate Rating of Installations as of December 31, 1979

					Existing		Under Construction		Authorized - Licensed		Potential		Project Totals	
Project	**Utility[1]**	**State**	**Stream**	**Initial Date in Service**	**No. of Units**	**Nameplate Rating-KW**	**No. of Units**	**Nameplate Rating-KW**	**No. of Units**	**Nameplate Rating-KW**	**No. of Units**	**Nameplate Rating-KW**	**No. of Units**	**Nameplate Rating-KW**
Minidoka	WPRS[2]	Idaho	Snake	May 7, 1909	7	13,400	—	—	—	—	—	—	7	13,400
Boise River Div.	WPRS	Idaho	Boise	May, 1912	3	1,500	—	—	—	—	—	—	3	1,500
Black Canyon	WPRS	Idaho	Payette	Dec, 1925	2	8,000	—	—	—	—	—	—	2	8,000
Bonneville	CE	Ore-Wash	Columbia	Jun 6, 1938	10	518,400	8-2	558,000[8]	—	—	—	—	10-2	1,076,400
Grand Coulee	WPRS	Wash	Columbia	Sep 28, 1941	23-3	5,463,000[4]	1	700,000[5]	—	—	6	4,200,000	30-3	10,363,000
Anderson Ranch	WPRS	Idaho	S. Fk. Boise	Dec 15, 1950	2	27,000	—	—	—	—	1	13,500	3	40,500
Hungry Horse	WPRS	Mont	S. Fk. Flathead	Oct 29, 1952	4	285,000	—	—	—	—	—	—	4	285,000
Detroit	CE	Oregon	N. Santiam	Jul 1, 1953	2	100,000	—	—	—	—	—	—	2	100,000
McNary	CE	Ore-Wash	Columbia	Nov 6, 1953	14	980,000	—	—	10	1,050,000	—	—	24	2,030,000
Big Cliff	CE	Oregon	N. Santiam	Jun 12, 1954	1	18,000	—	—	—	—	—	—	1	18,000
Lookout Point	CE	Oregon	M. Fk. Willamette	Dec 16, 1954	3	120,000	—	—	—	—	—	—	3	120,000
Albeni Falls	CE	Idaho	Pend Oreille	Mar 25, 1955	3	42,600	—	—	—	—	—	—	3	42,600
Dexter	CE	Oregon	M. Fk. Willamette	May 19, 1955	1	15,000	—	—	—	—	—	—	1	15,000
Chief Joseph	CE	Wash	Columbia	Aug 20, 1955	27	2,069,000	—	—	—	—	13	1,573,000	40	3,642,000
Chandler	WPRS	Wash	Yakima	Feb 13, 1956	2	12,000	—	—	—	—	—	—	2	12,000
Palisades	WPRS	Idaho	Snake	Feb 25, 1957	4	118,750	—	—	—	—	2	135,000	6	253,750
The Dalles	CE	Ore-Wash	Columbia	May 13, 1957	22-2	1,807,000[6]	—	—	—	—	—	—	22-2	1,807,000
Roza	WPRS	Wash	Yakima	Aug 31, 1958	1	11,250	—	—	—	—	—	—	1	11,250
Ice Harbor	CE	Wash	Snake	Dec 18, 1961	6	602,880	—	—	—	—	—	—	6	602,880
Hills Creek	CE	Oregon	M. Fk. Willamette	May 2, 1962	2	30,000	—	—	—	—	—	—	2	30,000
Cougar	CE	Oregon	S. Fk. McKenzie	Feb 4, 1964	2	25,000	—	—	1	35,000	—	—	3	60,000
Green Peter	CE	Oregon	Middle Santiam	Jun 9, 1967	2	80,000	—	—	—	—	—	—	2	80,000
John Day	CE	Ore-Wash	Columbia	Jul 17, 1968	16	2,160,000	—	—	4	540,000	—	—	20	2,700,000
Foster	CE	Oregon	South Santiam	Aug 22, 1968	2	20,000	—	—	—	—	—	—	2	20,000
Lower Monumental	CE	Wash	Snake	May 28, 1969	6	810,000	—	—	—	—	—	—	6	810,000
Little Goose	CE	Wash	Snake	May 19, 1970	6	810,000	—	—	—	—	—	—	6	810,000
Dworshak	CE	Idaho	N. Fk. Clearwater	Sep 18, 1974	3	400,000	—	—	3	660,000	—	—	6	1,060,000
Grand Coulee PG[3]	WPRS	Wash	Columbia	Dec 30, 1974	2	100,000	4	200,000	—	—	—	—	6	300,000
Lower Granite	CE	Wash	Snake	Apr 15, 1975	6	810,000	—	—	—	—	—	—	6	810,000
Libby	CE	Mont	Kootenai	Aug 29, 1975	4	420,000	4	420,000	—	—	—	—	8	840,000
Lost Creek	CE	Oregon	Rogue	Dec 1, 1977	2	49,000	—	—	—	—	—	—	2	49,000
Libby Reregulating	CE	Mont	Kootenai		—	—	3	76,400	—	—	—	—	3	76,400
Strube	CE	Oregon	S. Fk. McKenzie		—	—	—	—	1	4,500	—	—	1	4,500
Teton	WPRS	Idaho	Teton		—	—	—	—	3	30,000[7]	—	—	3	30,000
Total Number of Units and Nameplate Rating					**190-5**	**17,926,780**	**20-2**	**1,954,400**	**22**	**2,319,500**	**22**	**5,921,500**	**254-7**	**28,122,180**
Total Number of Projects						**30**		**1**		**2**		**0**		**33**

[1] CE—Corps of Engineers; WPRS—Water and Power Resources Service

[2] WPRS formerly was known as the Bureau of Reclamation

[3] PG—Pump Generation (Not counted in "Total Number of Projects")

[4] Includes three service units, an increase of 17,000 kW each for 17 rewound main units, three 600,000 kW units and two 700,000 kW unit at the Third Powerplant.

[5] One 700,000 kW unit is being installed at the Third Powerplant.

[6] 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.

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

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

Table 4

Sales of Electric Energy

Fiscal Year 1979

Customer	KWH (000)	Sales
Northwest Area Publicly-Owned Utilities Municipalities		
Albion, Idaho	3,281	$ 14,627
Bandon, OR	56,879	247,993
Blaine, WA	40,356	169,452
Bonners Ferry, ID	38,860	183,117
Burley, ID	111,968	434,183
Canby, OR	101,772	455,117
Cascade Locks, OR	34,512	141,681
Centralia, WA	110,647	519,042
Cheney, WA	103,816	432,178
Consolidated Irr. Dist., WA	1,968	10,072
Coulee Dam, WA	19,989	82,520
Delco, ID	2,768	12,708
Drain, OR	27,597	121,059
Eatonville, WA	12,464	53,977
Ellensburg, WA	152,829	618,847
Eugene, OR	1,701,528	5,909,568
Fircrest, WA	45,449	197,555
Forest Grove, OR	77,968	292,634[1]
Heyburn, ID	73,609	284,765
Idaho Falls, ID	409,344	1,678,376
McCleary, WA	36,313	158,201
McMinnville, OR	255,850	971,960[1]
Milton, WA	28,723	127,017
Milton-Freewater, OR	53,898	198,719[1]
Minidoka, ID	1,166	4,910
Monmouth, OR	60,761	273,574
Port Angeles, WA	634,521	2,501,998
Richland, WA	537,597	2,233,260
Rupert, ID	68,269	289,285
Seattle, WA	2,943,911	9,126,930[1]
Springfield, OR	714,612	2,771,985
Steilacoom, WA	38,674	171,888
Sumas, WA	7,179	30,345
Tacoma, WA	2,646,618	7,813,364[1]
Vera Irr. Dist., WA	152,444	649,439
Washington Public Power Supply	77,357	277,522
Total (36)	**11,385,497**	**$39,459,868**

Customer	KWH (000)	Sales
Public Utilities Districts		
Benton County PUD #1	1,330,850	5,159,719
Central Lincoln PUD	1,151,642	4,376,231
Chelan County PUD #1	382,772	1,646,516[1]
Clallam County PUD #1	441,500	1,939,762
Clark County PUD #1	2,651,004	10,496,012
Clatskanie PUD #1	713,623	2,532,953
Cowlitz PUD #1	2,851,981	9,213,964[1]
Douglas County PUD #1	337,832	1,148,643[1]
Ferry County PUD #1	61,732	250,126
Franklin County PUD #1	555,686	2,171,216
Grant County PUD #2	205,510	1,039,074[1]
Grays Harbor County PUD #1	1,226,086	4,475,015
Kittitas County PUD #1	29,274	119,067[1]
Klickitat County PUD #1	243,475	966,861
Lewis County PUD #1	672,307	2,471,476
Mason County PUD #1	60,565	264,613
Mason County PUD #3	394,286	1,710,145
Northern Wasco County PUD	223,327	940,914
Okanogan County PUD #1	450,673	1,772,924
Pacific County PUD #2	274,296	1,200,687
Pend Orielle County PUD #1	0	0
Skamania County PUD #1	113,556	474,343
Snohomish County PUD #1	4,797,293	18,509,268
Tillamook County PUD	360,389	1,538,103
Wahkiakum County PUD #1	46,898	197,636
Whatcom County PUD #1	124,306	420,811
Total PUD (26)	**19,700,863**	**75,036,079**

Pro Rata Breakdown by Plant Location

(Relates to Footnote 3)

Customer	MWH	Revenue
Aluminum Co. of America		
Addy	412,626	$ 1,219,613
Vancouver	1,755,476	5,188,727
Wenatchee	1,869,332	5,525,254
Kaiser Alum. & Chem. Corp.		
Spokane Reduction	3,580,569	10,567,817
Spokane Rolling	415,138	1,225,254
Tacoma Reduction	1,193,523	3,522,605
Reynolds Metals Co.		
Longview	3,234,057	9,482,297
Troutdale	2,114,144	6,198,697
Martin-Marietta		
Washington	1,592,193	4,036,271
Oregon	1,309,156	$ 3,313,590

Customer	KWH (000)	Sales
Cooperatives		
Alder Mutual Light Co.	2,284	$ 10,037
Benton Rural Electric Assn.	285,800	1,145,635
Big Bend Electric Coop.	418,732	1,511,702
Blachly-Lane Co. Coop. Elec. Assn.	117,432	488,108
Central Electric Coop.	291,158	1,245,134
Clearwater Power Co.	159,932	705,299
Columbia Basin Elec. Coop.	141,633	501,381
Columbia Power Coop. Assn.	28,510	105,989
Columbia Rural Elec. Assn.	161,754	601,208
Consumers Power	327,137	1,412,672
Coos-Curry Elec. Coop.	239,769	969,861
Douglas Elec. Coop.	140,403	595,658
Elmhurst Mutual Power & Light Co.	160,351	685,739
East End Mutual Elec. Co. Ltd.	13,058	51,779
Fall River Elec. Coop.	122,739	513,637
Farmers Elec. Co.	8,355	37,096
Flathead Elec. Coop.	124,447	502,223
Glacier Elec. Coop.	92,254	305,081
Harney Elec. Coop.	142,400	455,795
Hood River Elec. Coop.	86,569	360,710
Idaho Co. Light & Power Coop. Assn.	40,016	171,755
Inland Power & Light Co.	457,611	1,919,039
Kootenai Elec. Coop. Inc.	170,327	712,395
Lakeview Light & Power Co., Inc.	204,446	848,838
Lane Elec. Coop.	249,837	1,107,810
Lincoln Elec. Coop. Montana	58,955	246,087
Lincoln Elec. Coop.—WA.	128,648	454,602
Lost River Elec. Coop.	69,026	225,884
Lower Valley Power & Light Co.	257,599	1,014,973
Midstate Elec. Coop.	181,836	729,562
Missoula Elec. Coop.	119,146	487,186
Nespelem Valley Elec. Coop.	44,209	182,462
Northern Lights	148,571	603,064
Ohop Mutual Light Co.	31,592	144,845
Okanogan Co. Elec. Coop.	29,088	119,693
Peninsula Light Co.	271,704	1,181,662
Parkland Light & Water Co.	100,090	424,261
Orcas Power & Light Co.	108,673	462,181
Prairie Power Coop.	11,002	44,633
Raft River Elec. Coop.	220,494	758,571
Ravalli Elec. Coop.	81,081	331,660
Riverside Elec. Co.	7,058	31,088
Rural Elec. Co.	72,967	296,369
Salem. Elec.	247,103	1,039,056
Salmon River Elec. Coop.	39,847	132,303
South Side Elec. Lines	30,885	118,840
Surprise Valley Elec. Coop.	99,501	350,470
Tanner Elec. Co.	24,050	109,204
Umatilla Elec. Coop. Assn.	762,782	2,613,132
Unity Light & Power Co.	51,016	202,067
Vigilante Elec. Coop.	99,550	372,532
Wasco Elec. Coop.	97,018	412,670
Wells Rural Elec. Co.	46,753	169,061
West Oregon Elec. Coop.	66,964	288,063
Total Cooperatives (54)	**7,694,162**	**$ 30,510,762**
Total Publicly-Owned Utilities (116)	**38,780,522**	**$145,006,709**

[1]Includes capacity sales

[2]Financial transactions resulting from exchanges of capacity and energy

[3]See table at left

[4]Based on actual billings not including cost accounting accruals

Customer	KWH (000)	Sales
Privately-Owned Utilities		
California-Pacific Utilities Co.	6,810	21,473
Idaho Power Co.	371,528	1,160,430
Montana Power Co.	581,380	3,619,387[1]
Pacific Power & Light Co.	1,700,063	13,334,351[1]
Portland General Elec. Co.	1,524,166	10,854,016[1]
Puget Sound Power & Light Co.	1,430,592	6,760,770[1]
Utah Power Co.	233,334	719,913
Washington Water Power	671,330	2,579,571[1]
Total Privately-Owned Utilities (8)	**6,519,203**	**39,049,911**

Customer	KWH (000)	Sales
Federal Agencies		
U.S. Department of Energy	396,930	$ 1,378,281
U.S. Bureau of Mines	7,223	39,488
Fairchild Air Force Base	25,114	92,307
Water & Power Resources Service—Roza Project	12,782	51,125
U.S. Bureau of Indian Affairs	145,260	606,663
U.S. Navy	262,891	1,007,062
Total Federal Agencies (6)	**850,200**	**$ 3,174,926**

Customer	KWH (000)	Sales
Aluminum Industries		
Alcoa (combined)[3]	4,037,434	$ 11,933,594
Anaconda Alum. Co.	2,690,538	7,395,593
Martin Marietta, WA (combined)[3]	2,901,349	7,349,861
Intalco Alum. Co.	3,216,537	9,437,159
Kaiser Aluminum (combined)[3]	5,189,230	15,315,676
Reynolds Metal Co. (combined)[3]	5,348,201	15,680,994
Total Aluminum Industries (6)	**23,383,289**	**$ 67,112,877**

Customer	KWH (000)	Sales
Other Industries		
Carborundum Co.	213,218	$ 655,440
Crown-Zellerbach	67,337	155,745
Georgia-Pacific	84,256	219,327
Hanna Nickel	762,513	2,124,546
Cominco American	0	0
Oregon Metallurgical	47,911	195,465
Pacific Carbide	56,361	173,518
Pennwalt Corp.	340,594	1,020,618
Stewart Elsner	5	89
Union Carbide	95,836	246,391
Stauffer Chemical	429,442	1,402,753
Total Other Industries (11)	**2,097,473**	**6,193,892**
Total Northwest Region (147)	**71,630,814**	**$260,538,696**

Customer	KWH (000)	Sales
Outside Northwest Region		
Bountiful, Utah	127	$ 381
BC Hydro	0	0
Burbank, CA	5,619	−3,488[2]
Glendale, CA	8,432	−14,414[2]
Los Angeles, CA	104,713	−28,131[2]
Pasadena, CA	6,098	−5,634[2]
Sacramento, CA	0	0
Pacific Gas & Elec. Co.	126,772	5,570,316[1]
San Diego Gas & Elec. Co.	10,845	32,535
So. Cal. Edison Co.	115,158	345,474
State of California	0	0
WAPA—Mid-Pacific Region	14,880	779,640[1]
WAPA—Upper Colorado Region	0	0
WAPA—Upper Missouri Region	0	0
Total Outside Northwest Region (14)	**392,644**	**$ 6,676,679**
Total Sales of Electric Energy (161)	**72,023,331**	**$267,214,994[4]**

Table 5

Federal Columbia River Power System

1979 Wholesale Power Rate Filing Repayment Study

Projects in Service by July 1, 1981[1]

(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	Replacements	Total	Initial Project	Replacements	Total
Cumulative To 9-30-79	3,929,474	1,197,085	583,157	1,529,533	5,754,800		5,754,800	5,754,800		5,754,800
Adjustments[2]	38,641	(4,674)	(511)	(1,569)	361,801	1,530	363,331	361,801	1,530	363,331
1980	569,546	135,540	131,600	184,582	199,268	37,128	236,396	6,315,869	38,658	6,354,527
1981	662,000	140,384	248,749	194,472	154,410	1,900	156,310	6,470,279	40,558	6,510,837
1982	695,100	142,693	262,200	194,302		49,274	49,274	6,470,279	89,832	6,560,111
1983	697,600	142,079	254,637	188,090		25,063	25,063	6,470,279	114,895	6,585,174
1984	671,600	142,079	264,896	181,485		31,891	31,891	6,470,279	146,786	6,617,065
1985	689,300	142,079	268,890	176,109		34,715	34,715	6,470,279	181,501	6,651,780
1986	713,600	142,079	269,011	168,741		31,896	31,896	6,470,279	213,397	6,683,676
1987	717,900	142,079	268,911	162,244		44,635	44,635	6,470,279	258,032	6,728,311
1988	714,200	142,079	268,916	156,531		37,411	37,411	6,470,279	295,443	6,765,722
1989	686,100	142,079	270,216	152,148		49,439	49,439	6,470,279	344,882	6,815,161
1990	683,100	142,079	260,320	148,944		60,039	60,039	6,470,279	404,921	6,875,200
1991	677,100	142,079	232,179	145,419		52,815	52,815	6,470,279	457,736	6,928,015
1992	663,900	142,079	232,179	145,320		107,527	107,527	6,470,279	565,263	7,035,542
1993	661,100	142,079	232,179	145,192		44,961	44,961	6,470,279	610,224	7,080,503
1994	657,900	142,079	232,179	144,062		75,790	75,790	6,470,279	686,014	7,156,293
1995	654,600	142,079	232,179	143,007		50,692	50,692	6,470,279	736,706	7,206,985
1996	655,300	142,079	243,173	142,667		90,357	90,357	6,470,279	827,063	7,297,342
1997	667,400	142,079	276,153	144,129		76,287	76,287	6,470,279	903,350	7,373,629
1998	669,000	142,079	276,153	144,380		53,773	53,773	6,470,279	957,123	7,427,402
1999	671,700	142,079	276,153	143,457		64,652	64,652	6,470,279	1,021,775	7,492,054
2000	674,500	142,079	276,153	142,513		56,457	56,457	6,470,279	1,078,232	7,548,511
2001	674,400	142,079	276,153	142,152		76,902	76,902	6,470,279	1,155,134	7,625,413
2002	674,300	142,079	276,153	143,337		89,207	89,207	6,470,279	1,244,341	7,714,620
2003	673,900	142,079	276,153	143,377		56,297	56,297	6,470,279	1,300,638	7,770,917
2004	672,500	142,079	276,153	142,518		65,494	65,494	6,470,279	1,366,132	7,836,411
2005	672,500	142,079	276,153	142,627		63,675	63,675	6,470,279	1,429,807	7,900,086
2006	672,500	142,079	276,153	146,329		77,938	77,938	6,470,279	1,507,745	7,978,024
2007	672,500	142,079	276,153	151,031		92,915	92,915	6,470,279	1,600,660	8,070,939
2008	672,500	142,079	276,153	155,614		68,237	68,237	6,470,279	1,668,897	8,139,176
2009	672,500	142,079	276,153	159,898		77,702	77,702	6,470,279	1,746,599	8,216,878
2010	670,600	142,079	276,153	165,385		108,279	108,279	6,470,279	1,854,878	8,325,157
2011	662,600	142,079	262,153	175,251		193,847	193,847	6,470,279	2,048,725	8,519,004
2012	657,100	142,079	246,153	184,121		108,908	108,908	6,470,279	2,157,633	8,627,912
2013	657,100	142,079	246,153	191,470		104,630	104,630	6,470,279	2,262,263	8,732,542
2014	657,100	142,079	246,153	196,776		75,761	75,761	6,470,279	2,338,024	8,808,303
2015	657,100	142,079	246,153	202,014		69,533	69,533	6,470,279	2,407,557	8,877,836
2016	657,100	142,079	246,153	212,377		201,895	201,895	6,470,279	2,609,452	9,079,731
2017	657,100	142,079	137,419	220,114		68,444	68,444	6,470,279	2,677,896	9,148,175
2018	657,100	142,079	137,419	224,879		93,833	93,833	6,470,279	2,771,729	9,242,008
2019	657,100	142,079	75,106	226,583		69,812	69,812	6,470,279	2,841,541	9,311,820
2020	657,100	142,079		227,663		103,893	103,893	6,470,279	2,945,434	9,415,713
2021	657,100	142,079		221,843		89,428	89,428	6,470,279	3,034,862	9,505,141
2022	657,100	142,079		213,360		97,135	97,135	6,470,279	3,131,997	9,602,276
2023	657,100	142,079		199,769		69,050	69,050	6,470,279	3,201,047	9,671,326
2024	657,100	142,079		196,323		79,893	79,893	6,470,279	3,280,940	9,751,219
2025	657,100	142,079		195,159		73,329	73,329	6,470,279	3,354,269	9,824,548
2026	657,100	142,079		195,385		103,443	103,443	6,470,279	3,457,712	9,927,991
2027	657,100	142,079		194,970		95,183	95,183	6,470,279	3,552,895	10,023,174
2028	657,100	142,079		189,937		75,632	75,632	6,470,279	3,628,527	10,098,806
2029	657,100	142,079		187,867		92,535	92,535	6,470,279	3,721,062	10,191,341
2030	657,100	142,079		185,394		72,519	72,519	6,470,279	3,793,581	10,263,860
2031	657,100	142,079		163,853		106,205	106,205	6,470,279	3,899,786	10,370,065
2032	657,100	142,079		145,006		112,437	112,437	6,470,279	4,012,223	10,482,502
2033	657,100	142,079		119,004		70,746	70,746	6,470,279	4,082,969	10,553,248
2034	657,100	142,079		88,666		81,344	81,344	6,470,279	4,164,313	10,634,592
2035	657,100	142,079		57,763		75,129	75,129	6,470,279	4,239,442	10,709,721
2036	657,100	142,079		29,611		92,288	92,288	6,470,279	4,331,730	10,802,009
2037	657,100	142,079		939		88,225	88,225	6,470,279	4,419,955	10,890,234
2038	657,100	142,079		17,116—		74,054	74,054	6,470,279	4,494,009	10,964,288
2039	657,100	142,079		16,728—		83,618	83,618	6,470,279	4,577,627	11,047,906
2040	657,100	142,079		16,386—		92,110	92,110	6,470,279	4,669,737	11,140,016
2041	657,100	142,079		16,003—		101,570	101,570	6,470,273	4,771,307	11,241,586
2042	657,100	142,079		14,279—		144,493	144,493	6,470,279	4,915,800	11,386,079
2043	657,100	142,079		16,906—		78,792	78,792	6,470,279	4,994,592	11,464,871
2044	657,100	142,079		16,467—		89,577	89,577	6,470,279	5,084,169	11,554,448
2045	657,100	142,079		15,306—		118,524	118,524	6,470,279	5,202,693	11,672,972
2046	657,100	142,079		12,306—		193,433	193,433	6,470,279	5,396,126	11,866,405
2047	657,100	142,079		15,655—		109,548	109,548	6,470,279	5,505,674	11,975,953
2048	657,100	142,079		15,111—		123,035	123,035	6,470,279	5,628,709	12,098,988
2049	657,100	142,079		16,838—		79,650	79,650	6,470,279	5,708,359	12,178,638
2050	657,100	142,079		16,508—		87,855	87,855	6,470,279	5,796,214	12,266,493
2051	657,100	142,079		16,215—		95,008	95,008	6,470,279	5,891,222	12,361,501
2052	657,100	142,079		16,101—		97,894	97,894	6,470,279	5,989,116	12,459,395
2053	657,100	142,079		16,770—		81,540	81,540	6,470,279	6,070,656	12,540,935
2054	657,100	142,079		16,257—		94,454	94,454	6,470,279	6,165,110	12,635,389
2055	657,100	142,079		16,691—		83,879	83,879	6,470,279	6,248,989	12,719,268
2056	657,100	142,079		11,422—		215,507	215,507	6,470,279	6,464,496	12,934,775
2057	657,100	142,079		16,567—		86,748	86,748	6,470,279	6,551,244	13,021,523
2058	657,100	142,079		15,763—		106,776	106,776	6,470,279	6,658,020	13,128,299
2059	657,100	142,079		15,953—		101,951	101,951	6,470,279	6,759,971	13,230,250
2060	657,100	142,079		15,278—		118,885	118,885	6,470,279	6,878,856	13,349,135
2061	657,100	142,079		16,355—		92,050	92,050	6,470,279	6,970,906	13,441,185
2062	657,100	142,079		13,915—		153,390	153,390	6,470,279	7,124,296	13,594,575
2063	657,100	142,079		17,029—		75,711	75,711	6,470,279	7,200,007	13,670,286
2064	657,100	142,079		16,166—		97,567	97,567	6,470,279	7,297,574	13,767,853
2065	657,100	142,079		17,251—		71,048	71,048	6,470,279	7,368,622	13,838,901
Totals	60,994,861	13,403,585	10,464,064	10,570,781	6,470,279	7,368,622	13,838,901			

1	12	13	14	15	16	17	18	19	20	21	22
	COMMERCIAL POWER						IRRIGATION ASSISTANCE				
			Allowable Unamortized Investment								
Fiscal Year Ending Sept. 30	Amortization	Unamortized Investment	Initial Project	Replacements	Total	Cumulative Amount in Service	Amortization	Unamortized Amount	Allowable Unamortized Amount	Cumulative Surplus Revenues	Fiscal Year Ending Sept. 30
Cumulative To 9-30-79	619,699	5,135,101	5,685,834		5,685,834	627,174		627,174	627,174		1979
Adjustments[2]	45,395	317,936	361,801	1,530	363,331	4,430		4,430	4,430		
1980	117,824	5,571,609	6,242,231	38,658	6,280,889	631,604		631,604	631,604		1980
1981	78,395	5,649,524	6,393,421	40,558	6,433,979	631,604		631,604	631,604		1981
1982	95,905	5,602,893	6,390,318	89,832	6,480,150	635,323		635,323	635,323		1982
1983	112,794	5,515,162	6,380,560	114,895	6,495,455	702,117		702,117	702,117		1983
1984	83,140	5,463,913	6,371,032	146,785	6,517,817	735,996		735,996	735,996		1984
1985	102,222	5,396,406	6,340,797	181,473	6,522,270	799,831		799,831	799,831		1985
1986	133,769	5,294,533	6,320,491	213,343	6,533,834	833,608		833,608	833,608		1986
1987	144,666	5,194,502	6,292,902	257,936	6,550,838	873,210		873,210	873,210		1987
1988	146,674	5,085,239	6,224,456	295,335	6,519,791	898,940		898,940	898,940		1988
1989	121,657	5,013,021	6,179,357	344,680	6,524,037	937,191		937,191	937,191		1989
1990	131,757	4,941,303	6,154,065	404,619	6,558,684	959,574		959,574	959,574		1990
1991	157,423	4,836,695	6,060,944	457,377	6,518,321	985,095		985,095	985,095		1991
1992	144,322	4,799,900	6,000,701	564,710	6,565,411	1,031,383		1,031,383	1,031,383		1992
1993	141,650	4,703,211	5,929,561	609,512	6,539,073	1,064,378		1,064,378	1,064,378		1993
1994	139,580	4,639,421	5,877,577	685,169	6,562,746	1,091,819		1,091,819	1,091,819		1994
1995	137,335	4,552,778	5,866,818	735,101	6,601,919	1,119,388		1,119,388	1,119,388		1995
1996	127,381	4,515,754	5,844,388	825,270	6,669,658	1,142,496		1,142,496	1,142,496		1996
1997	90,319	4,501,722	5,808,327	900,757	6,709,084	1,165,706	14,720	1,150,986	1,150,986		1997
1998	106,388	4,449,107	5,761,459	953,597	6,715,056	1,178,455		1,163,735	1,163,735		1998
1999	110,011	4,403,748	5,716,265	1,016,783	6,733,048	1,214,538		1,199,818	1,199,818		1999
2000	113,755	4,346,450	5,655,810	1,070,541	6,726,351	1,252,439		1,237,719	1,237,719		2000
2001	103,768	4,319,584	5,577,821	1,145,943	6,723,764	1,275,222	10,248	1,250,254	1,250,254		2001
2002	112,731	4,296,060	5,513,057	1,229,753	6,742,810	1,298,103		1,273,135	1,273,135		2002
2003	112,291	4,240,066	5,297,979	1,284,466	6,582,445	1,320,802		1,295,834	1,295,834		2003
2004	110,969	4,194,591	5,067,957	1,347,606	6,415,563	1,343,598	781	1,317,849	1,317,849		2004
2005	111,641	4,146,625	4,724,898	1,409,275	6,134,173	1,374,844		1,349,095	1,349,095		2005
2006	107,939	4,116,624	4,559,748	1,475,265	6,035,012	1,403,227		1,377,478	1,377,478		2006
2007	103,237	4,106,302	4,380,268	1,567,111	5,947,379	1,440,280		1,414,531	1,414,531		2007
2008	95,703	4,078,836	4,151,080	1,634,321	5,785,401	1,470,910	2,951	1,442,210	1,442,210		2008
2009	88,129	4,068,409	4,007,263	1,710,051	5,717,314	1,501,954	6,241	1,467,013	1,467,013		2009
2010	86,983	4,089,705	3,843,166	1,815,010	5,658,176	1,517,542		1,482,601	1,482,601		2010
2011	83,117	4,200,435	3,751,264	2,007,414	5,758,678	1,541,308		1,506,367	1,506,367		2011
2012	84,244	4,225,099	3,467,095	2,113,237	5,580,332	1,565,173	503	1,529,729	1,529,729		2012
2013	39,780	4,289,949	3,376,601	2,215,667	5,592,268	1,599,057	37,618	1,525,995	1,525,995		2013
2014	30,782	4,334,928	3,243,066	2,286,191	5,529,257	1,627,281	41,310	1,512,909	1,512,909		2014
2015	22,086	4,382,375	3,070,066	2,351,038	5,421,104	1,655,505	44,768	1,496,365	1,496,365		2015
2016	7,774—	4,592,044	2,979,066	2,547,285	5,526,351	1,677,149	64,265	1,453,744	1,453,744		2016
2017	102,290	4,558,198	2,954,227	2,588,033	5,542,260	1,698,793	55,198	1,420,190	1,420,190		2017
2018	132,451	4,519,580	2,881,330	2,652,847	5,534,177	1,732,721	20,272	1,433,846	1,433,846		2018
2019	153,198	4,436,194	2,589,028	2,693,133	5,282,161	1,761,968	60,134	1,402,959	1,402,959		2019
2020	260,820	4,279,267	2,451,346	2,730,270	5,181,616	1,794,143	26,538	1,408,596	1,408,596		2020
2021	274,509	4,094,186	2,324,113	2,777,659	5,101,772	1,823,390	18,669	1,419,174	1,419,174		2021
2022	284,129	3,907,192	2,276,056	2,814,562	5,090,618	1,844,011	17,532	1,422,263	1,422,263		2022
2023	309,126	3,667,116	2,235,236	2,846,385	5,081,621	1,864,632	6,126	1,436,758	1,436,758		2023
2024	301,306	3,445,703	2,127,554	2,878,582	5,006,136	1,884,813	17,392	1,439,547	1,439,547		2024
2025	311,230	3,207,802	1,500,245	2,907,403	4,407,648	1,904,995	8,632	1,451,097	1,451,097		2025
2026	300,201	3,011,044	1,077,957	2,967,899	4,045,356	1,932,781	19,435	1,459,448	1,459,448		2026
2027	316,992	2,789,235	933,761	2,993,823	3,927,584	1,960,567	3,059	1,484,175	1,484,175		2027
2028	306,741	2,558,126	558,049	3,025,337	3,583,386	1,980,162	18,343	1,485,427	1,485,427		2028
2029	322,980	2,327,681	89,678	3,049,706	3,139,384	1,999,758	4,174	1,500,849	1,500,849		2029
2030	327,162	2,073,038	63,410	3,072,377	3,135,787	2,036,028	2,465	1,534,654	1,534,654		2030
2031	341,954	1,837,289		3,094,177	3,094,177	2,071,125	9,214	1,560,537	1,560,537		2031
2032	370,015	1,579,711		3,115,181	3,115,181	2,103,591		1,593,003	1,593,003		2032
2033	396,017	1,254,440		3,135,432	3,135,432	2,134,731		1,624,143	1,624,143		2033
2034	418,843	916,941		3,154,995	3,154,995	2,153,515	7,512	1,635,415	1,635,415		2034
2035	436,826	555,244		3,173,880	3,173,880	2,172,139	20,432	1,633,607	1,633,607		2035
2036	449,856	197,676		3,192,171	3,192,171	2,172,139	35,554	1,598,053	1,598,053		2036
2037	285,901			3,209,884	3,209,884	2,172,139	31,987	1,566,066	1,566,066	196,194	2037
2038	74,054			3,227,057	3,227,057	2,172,139		1,566,066	1,566,066	654,277	2038
2039	83,618			3,243,747	3,243,747	2,172,139	14,248	1,551,818	1,551,818	1,088,160	2039
2040	92,110			3,260,004	3,260,004	2,172,139		1,551,818	1,551,818	1,527,457	2040
2041	101,570			3,275,878	3,275,878	2,172,139	22,821	1,528,997	1,528,997	1,934,090	2041
2042	144,493			3,291,423	3,291,423	2,172,139	22,495	1,506,502	1,506,502	2,296,402	2042
2043	78,792			3,306,713	3,306,713	2,172,139	24,272	1,482,230	1,482,230	2,725,265	2043
2044	89,577			3,321,847	3,321,847	2,172,139	57,281	1,424,949	1,424,949	3,109,895	2044
2045	118,524			3,336,871	3,336,871	2,172,139	42,008	1,382,941	1,382,941	3,479,690	2045
2046	193,433			3,351,837	3,351,837	2,172,139	15,001	1,367,940	1,367,940	3,798,583	2046
2047	109,548			3,366,861	3,366,861	2,172,139	20,825	1,347,115	1,347,115	4,198,886	2047
2048	123,035			3,382,031	3,382,031	2,172,139	25,730	1,321,385	1,321,385	4,580,253	2048
2049	79,650			3,397,447	3,397,447	2,172,139	38,251	1,283,134	1,283,134	4,994,211	2049
2050	87,855			3,413,153	3,413,153	2,172,139	22,383	1,260,751	1,260,751	5,415,502	2050
2051	95,008			3,429,206	3,429,206	2,172,139	25,521	1,235,230	1,235,230	5,826,209	2051
2052	97,894			3,444,734	3,444,734	2,172,139	46,288	1,188,942	1,188,942	6,213,149	2052
2053	81,540			3,457,596	3,457,596	2,172,139	32,995	1,155,947	1,155,947	6,630,405	2053
2054	94,454			3,469,791	3,469,791	2,172,139	27,441	1,128,506	1,128,506	7,039,788	2054
2055	83,879			3,480,072	3,480,072	2,172,139	27,569	1,100,937	1,100,937	7,460,052	2055
2056	215,507			3,490,719	3,490,719	2,172,139	23,108	1,077,829	1,077,829	7,747,880	2056
2057	86,748			3,501,804	3,501,804	2,172,139	23,210	1,054,619	1,054,619	8,169,510	2057
2058	106,776			3,512,988	3,512,988	2,172,139	12,749	1,041,870	1,041,870	8,580,769	2058
2059	101,951			3,524,277	3,524,277	2,172,139	36,083	1,005,787	1,005,787	8,973,709	2059
2060	118,885			3,535,098	3,535,098	2,172,139	37,901	967,886	967,886	9,347,222	2060
2061	92,050			3,545,343	3,545,343	2,172,139	22,783	945,103	945,103	9,763,765	2061
2062	153,390			3,553,183	3,553,183	2,172,139	22,881	922,222	922,222	10,116,430	2062
2063	75,711			3,559,927	3,559,927	2,172,139	22,699	899,523	899,523	10,550,070	2063
2064	97,567			3,564,778	3,564,778	2,172,139	22,796	876,727	876,727	10,960,894	2064
2065	71,048			3,566,149	3,566,149	2,172,139	31,246	845,481	845,481	11,390,872	2065
Totals	13,838,901						1,326,658				

[1] See note on page 42.

[2] The adjustments line represents the difference between 1979 actual results and the 1979 estimates originally included in the repayment study. Repayment study estimates are based upon the presumption of average conditions, but 1979 was a below-average year due to poor streamflows. The effect of a below-average year over the long run can be expected to be offset by the occurrence of some above-average years at some time within the repayment period.

Repayment Policy

The basis on which BPA establishes its revenue requirements, and hence its rate level, is the repayment policy. This policy, which is based upon the Department of Energy's interpretation of statutory requirements, provides that FCRPS revenues from power sales, wheeling service and other miscellaneous sources must be sufficient to satisfy the following criteria:

1. Pay the cost of obtaining power through purchase and exchange agreements.
2. Pay the cost of operating and maintaining the power system.
3. Pay interest on and 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 are all financed with appropriated funds. BPA transmission facilities constructed prior to BPA's authorization to finance its construction program with sales receipts and revenue bonds were financed with appropriated funds.)
5. Repay, with interest, any outstanding unpaid annual expenses.
6. Repay each increment of the power investment at the Federal hydroelectric projects within 50 years after such increment becomes revenue producing.
7. Repay 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 (currently 35 years).
8. Repay 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.)

9. 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.

Note to Federal Columbia River Power System Repayment Study

(Table 5, Page 40)

Section 2 of Public Law 89-448 (80 STAT 200) requires the submission to the President and the Congress of an annual financial statement which includes all projects authorized by Congress as components of the Federal Columbia River Power System. BPA previously fulfilled that requirement by publishing the Federal Columbia River Power System Repayment Study in its annual report and transmitting copies thereof to the President and the Congress. Through FY 1978 the FCRPS repayment study included the estimated costs of all authorized projects even though some were not yet in service or in some cases not yet under construction. For determining revenue requirements for the purpose of establishing power rates, however, objections were raised by customers to the inclusion of projects in the repayment study which would not be in service during the period the power rates would be in effect. During preparation of the proposed power rate increase to take effect December 20, 1979, the BPA General Counsel issued an opinion concluding that whereas PL 89-448 does, in fact, require the inclusion of all authorized projects in the annual financial statement to be submitted to the President and the Congress, the repayment study used as a basis for establishing rate levels should properly include only those projects which will be in service during the rate period. The FCRPS repayment study included in this report is the same one used to determine the amount of the 1979 rate increase, i.e., it includes only those Federal power facilities expected to be in service during the rate period from December 20, 1979, through June 30, 1981.

The authorized projects not included in the repayment study, their estimated capital investments in 1980 dollars and their estimated completion dates are set forth in the table below.

These projects will be included in future repayment studies for rate-setting purposes as they are completed and placed into service and will be reported pursuant to the requirement of PL 89-448 by inclusion in the BPA annual report.

Bonneville Dam Second Power Plant	Jul 1982	$710 million
Grand Coulee Pump Generator Units No. 11 and No. 12	Dec 1981	$ 17 million
Libby Units No. 5 through No. 8	Nov 1983	$315 million
Libby Reregulation Project	May 1984	$ 62 million
Cougar Unit No. 3	Sep 1985	$ 36 million
Strube Unit No. 1	Sep 1985	$ 42 million
McNary Second Power House	Jul 1994	$583 million
Dworshak additional units	Jul 1997	$150 million
John Day additional units	Jul 1997	$110 million

Accountants' 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, 1979 and 1978, and the related statements of revenues and expenses, changes in federal investment and source and use of funds for the fiscal years then ended. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

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.

As described in Note 1 under the caption, Regulatory Authorities, wheeling rate increases which have been collected under a temporary rate order are subject to refund with interest in the event of regulatory disapproval.

In our opinion, subject to the effects, if any, on the financial statements of the resolution of the tentative cost allocations and wheeling rate proceeding discussed in the two preceding paragraphs, the financial statements referred to above present fairly the assets and liabilities of the Federal Columbia River Power System at September 30, 1979 and 1978, and its revenues and expenses, changes in federal investment and source and use of funds for the fiscal years then ended, in conformity with accounting principles described in Note 1 applied on a consistent basis.

Supplemental Schedule A showing the amount and allocation of plant investment as of September 30, 1979 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 12, 1979

Coopers & Lybrand

Federal Columbia River Power System

Statement of Revenues and Expenses

for the fiscal years ended September 30, 1979 and 1978

	Fiscal Year 1979	Fiscal Year 1978
	(Thousands of Dollars)	
OPERATING REVENUES (Note 1):		
Sales of electric power:		
Publicly owned utilities	$146,796	$136,373
Privately owned utilities	48,131	68,475
Federal agencies	4,840	8,764
Aluminum industry	53,168	74,676
Other industry	4,584	7,379
	257,519	**295,667**
Other operating revenues:		
Wheeling	27,843	25,562
Other	11,197	12,735
	39,040	**38,297**
Total operating revenues	**296,559**	**333,964**
OPERATING EXPENSES:		
Operation	76,547	68,184
Maintenance	46,601	41,914
Total operation and maintenance expense	**123,148**	**110,098**
Purchase and exchange power (Note 1)	25,195	51,130
Depreciation	50,164	47,580
Total operating expenses	**198,507**	**208,808**
Net operating revenues	**98,052**	**125,156**
INTEREST EXPENSE (Notes 2, 3, 4 and 7):		
Interest on Federal investment:		
On appropriated funds	173,337	162,869
On Transmission System Act borrowings	24,635	6,210
Allowance for funds used during construction	(29,971)	(26,859)
Net interest expense	**168,001**	**142,220**
NET REVENUES (EXPENSE)	**$(69,949)**	**$(17,064)**

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

Federal Columbia River Power System

Statement of Assets and Liabilities

at September 30, 1979 and 1978

Assets

	September 30, 1979	September 30, 1978
	(Thousands of Dollars)	
UTILITY PLANT (Notes 2 and 3):		
Completed plant (Schedule A)	$5,599,965	$5,386,878
Accumulated depreciation	(469,567)	(427,884)
	5,130,398	4,958,994
Construction work in progress (Schedule A)	884,655	758,028
Net utility plant	**6,015,053**	**5,717,022**
CURRENT ASSETS:		
Unexpended funds (Note 4)	75,306	78,981
Accounts receivable	8,119	14,957
Accrued unbilled revenues	20,668	18,373
Materials and supplies, at average cost	26,465	25,981
Total current assets	**130,558**	**138,292**
OTHER ASSETS AND DEFERRED CHARGES:		
Trust funds (Note 6)	8,700	5,967
Net billing advances, less amortization (Note 5)	246,861	153,445
Investment in Teton Dam (Note 9)	13,741	13,637
Other	11,968	9,540
Total other assets and deferred charges	**281,270**	**182,589**
	$6,426,881	**$6,037,903**

Liabilities and Federal Investment

	1979	1978
FEDERAL INVESTMENT:		
Net investment of U.S. Government in power facilities (Note 7)	$6,075,734	$5,635,242
Accumulated net revenues	242,129	312,078
Irrigation assistance (Schedule A and Note 8) $627 million and $608 million, respectively		
Total federal investment	**6,317,863**	**5,947,320**
COMMITMENTS AND CONTINGENCIES: (Notes 1, 2, 3, 5, 8, 9 and 10)		
CURRENT LIABILITIES:		
Accounts payable	86,121	71,006
Employees accrued leave	8,311	7,874
Total current liabilities	**94,432**	**78,880**
DEFERRED CREDITS:		
Trust fund advances (Note 6)	8,700	5,967
Other	5,886	5,736
Total deferred credits	**14,586**	**11,703**
	$6,426,881	**$6,037,903**

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

Federal Columbia River Power System

Statement of Changes in Federal Investment

for the fiscal years ended September 30, 1979 and 1978

	Balance October 1, 1977	Additions (Reductions)	Balance September 30, 1978	Additions (Reductions)	Balance September 30, 1979
		(Thousands of Dollars)			
Congressional appropriations	$6,206,970	$254,919	$6,461,889	$260,772	$6,722,661
U.S. Treasury transfers to Continuing Fund	7,005		7,005		7,005
Transfers from (to) other federal agencies, net	41,338	7,547	48,885	(4,258)	44,627
Federal Columbia River Transmission System Act borrowings (Note 2)	125,000	175,000	300,000	110,000	410,000
Interest on federal investment:					
On appropriated funds	1,622,472	162,869	1,785,341	74,753	1,860,094
On Transmission System Act borrowings		6,210	6,210	24,635	30,845
Unpaid annual expense (Note 7)				98,584	98,584
Less funds returned to U.S. Treasury	(2,780,280)	(193,808)	(2,974,088)	(123,994)	(3,098,082)
Net investment of U.S. government	5,222,505	412,737	5,635,242	440,492	6,075,734
Accumulated net revenues	329,142	(17,064)	312,078	(69,949)	242,129
Total federal investment	**$5,551,647**	**$395,673**	**$5,947,320**	**$370,543**	**$6,317,863**

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, 1979 and 1978

	Fiscal Year 1979	Fiscal Year 1978
	(Thousands of Dollars)	
SOURCE OF FUNDS:		
Operations:		
Net revenues (expense)	$(69,949)	$(17,064)
Charges not requiring funds:		
Depreciation	50,164	47,580
Amortization of net billing advances	3,503	10,010
Funds provided from (used in) operations	(16,282)	40,526
Increase in net investment of U.S. Government	440,492	412,737
Decrease (increase) in current assets:		
Unexpended funds	3,675	15,501
Receivables	4,543	(14,813)
Materials and supplies	(484)	(148)
Increase (decrease) in current liabilities	15,552	(27,799)
Total funds provided	**$447,496**	**$426,004**
USE OF FUNDS:		
Investment in utility plant, net	$348,195	$359,903
Increase in net billing advances	96,919	66,006
Other, net	2,382	95
Total funds used	**$447,496**	**$426,004**

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 Energy Regulatory Commission (FERC). FCRPS accounting policies described herein also reflect requirements of specific legislation and executive directives issued by the involved government departments (BPA is a unit of the Department of Energy; 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, payment to the U.S. Treasury for debt service on borrowings and for its investment in power facilities and interest thereon, and costs of net billed thermal 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.

If revenues in any year are not sufficient to meet all required payments, the priority for use of revenues is: net billing credits; additional payments required for net billed thermal projects and BPA operating expenses; debt service on Federal Columbia River Transmission System Act borrowings from the U.S. Treasury; Corps and Bureau operating expenses; interest on unpaid annual expense and on the Federal investment in power facilities financed through appropriations; amortization of unpaid annual expense (see Note 7); amortization of the Federal investment in power facilities financed through appropriations; irrigation repayment assistance. Presently no irrigation repayment assistance is required until 1997. If insufficient cash is available to meet all payment obligations, the priority order for the application of revenues will be used in reverse order to determine what payments will be deferred. 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 are intended to provide 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 35 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, current rates are intended to provide for recovery of advances for net billed thermal projects under construction, which amounts will not be charged to expense until the projects become operational.

Regulatory Authorities

Effective January 1, 1979, the Secretary of Energy delegated authority to the Assistant Secretary for Resource Applications to develop, acting by and through the Administrator, and to confirm, approve and place in effect on an interim basis, power and transmission rates. At the same time, the Federal Energy Regulatory Commission (FERC) was given authority to confirm and approve on a final basis, or to disapprove, such rates. Refunds are authorized if rates finally approved are lower than rates approved on an interim basis.

Under terms of BPA's current power sales contracts, rates can only be adjusted as of December 20, 1979 or July 1, 1980; July 1, 1981 and each July 1 thereafter. The present rates were approved by the FPC effective on December 20, 1974. Wheeling rates charged for transmission of nonfederal power were increased approximately 22% on July 1, 1977 under a temporary FPC rate order final approval of which is currently pending before the FERC. Revenues applicable to these rate increases, which revenues are subject to refund with interest in the event of regulatory disapproval, totaled approximately $15.3 million at September 30, 1979 (including $8.8 million in 1979 and $5.75 million in 1978).

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 2-1/2 % to 3-1/4 %). Service lives currently average approximately 35 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 plant in service, approximated 2.0% in 1979 and 1.9% in 1978 for transmission plant and 0.4% in each such year for generating plant.

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 (2-1/2 % to 3-1/4 %) and rates approximating the cost of borrowings from the U.S. Treasury for other construction (7% to 9% during the two years ended September 30, 1979).

Thermal Plant 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, amounts may be payable by BPA in respect to its share of the operating Trojan Nuclear project (principally related to fuel purchases, major plant additions and additions to debt service reserves) prior to the periods in which related economic benefits accrue. These payments and billing credits, less amortization, are included as deferred charges under the caption "net billing advances" in the accompanying statement of assets and liabilities. After the date of commencement of commercial operation, advances are amortized over a project's estimated useful life (approximately 35 years) or 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 $11.0 million in 1979 and $8.5 million in 1978.

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.

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. 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.

Following is a summary of borrowings and repayments under the Act:

	Notes		Bonds		
	Borrowings (Repayments)		Borrowings		
Date	Millions	Rate	Millions	Rate	Maturity
9/30/77	$125	6.73%			
9/30/78	(125)				
9/30/78	250	9.125	$ 50	8.95%	9/30/2013
6/30/79	(75)		75	9.45	6/30/2014
9/30/79	(175)				
9/30/79	235	10.5	50	9.90	9/30/2014
Outstanding at 9/30/79	$235		$175		

BPA's borrowing authority within the aforementioned $1.25 billion maximum is limited at any one time to its cumulative expenditures for transmission plant (including capitalized interest and any unspent approved construction budget amounts) which have not been financed from appropriations. At September 30, 1979, BPA had borrowed substantially all funds available within this limitation other than the approved 1980 construction budget. The $235 million note outstanding is payable by September 30, 1981.

BPA's construction budget for fiscal year 1980 is $103 million for which substantial commitments have been incurred. Fiscal 1980 construction appropriations for power facilities have been authorized by Congress for the Corps and the Bureau totaling $177 million and $17 million, respectively.

Note 3. Tentative Cost Allocations:

Allocations of plant cost and operation and maintenance expenses between power and nonpower purposes for six system projects are presently based on tentative allocations. At September 30, 1979, total costs for these six projects approximated $2.1 billion of which $1.6 billion was tentatively allocated to power and subject to adjustment. In prior years, adjustments were 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 for these six projects 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, 1979	September 30, 1978
	(Thousands of Dollars)	
Corps and Bureau unexpended appropriated funds	$47,999	$57,110
BPA cash balances with U.S. Treasury	27,307	21,871
	$75,306	$78,981

FCRPS receives credit for interest on unexpended appropriated funds by deducting them from the unamortized federal investment in determining the required interest on the federal investment. The Treasury gives BPA credit for its cash balances in determining interest charges. The interest expense on Treasury borrowings reflects reductions of $2.8 million in 1979 and $2.2 million in 1978 arising from credits for cash balances.

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. Annual project budgets have not included provisions for any future costs associated with spent fuel reprocessing, off-site storage of spent fuel or plant decommissioning.

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, 1979:

Project and % Capability Acquired	Projected in Service Date	Estimated BPA Portion: Capacity in Megawatts	Estimated BPA Portion: Present Termination Commitment	Estimated BPA Portion: Additional Estimated Financing Requirements for Projects under Construction
			(Thousands of Dollars)	
WPPSS* Hanford Project (100%)	Operational	860	$ 48,855	
Net billed projects:				
Trojan Nuclear project (30%)	Operational	339	149,915	
WPPSS* Nuclear Project #1 (100%)	Dec 1983	1,250	1,045,000	$877,000
WPPSS* Nuclear Project #2 (100%)	Sept 1981**	1,100	1,147,000	280,000
WPPSS* Nuclear Project #3 (70%)	Dec 1984	868	680,000	698,000

*Washington Public Power Supply System

**Several factors relating to construction and scheduling are currently reducing the probability of achieving this projected in-service date.

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, 1980 to give BPA notification of its intention to withdraw project capability.

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. It is expected that any withdrawal would be in annual increments over a period of years. No such withdrawal options exist for the WPPSS projects. See Note 1 for information concerning net billing advances. Amounts shown therefor in the accompanying statement of assets and liabilities comprise:

	September 30, 1979	September 30, 1978
	(Thousands of Dollars)	
Trojan Nuclear Project, net of accumulated amortization of $14,426 and $10,923	$45,113	$39,972
Washington Public Power Supply System Nuclear Project No. 2 (under construction)	201,748	113,473
	$246,861	$153,445

BPA has also entered into agreement with a group of utilities to exchange an agreed amount of power for their rights to a portion of the Canadian Entitlement (one-half of the additional power benefits realized by downstream U.S. projects from three Canadian Treaty dams for a 60-year period). 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 660 megawatts currently to approximately 100 megawatts in the last year of the exchange agreement (2003).

Note 6. Trust Funds and Trust Fund Advances:

These balance sheet amounts are comprised of funds received by BPA from customers and others for the purchase of nonfederal power for customers' benefit and for construction to be done for others.

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 35 years, respectively, from the time the facility is placed in service. No such repayments are required during the next five years. However, amounts are normally expected to be paid annually for interest on outstanding Federal investment, net of interest capitalized on projects financed through appropriations, and for operating expenses of the Corps and Bureau funded by annual appropriations. To the extent that funds are not available for payment, such amounts become payable from subsequent years' revenue prior to any payment for amortization of Federal investment. Fiscal year 1979 revenues were not sufficient to pay all these annual amounts and payment of $98.6 million of interest on appropriated funds has been deferred ($58.9 million BPA interest and $39.7 million Corps interest).

Interest rates (other than on Transmission System Act borrowings) range from 2-1/2 to 7-1/8% (the weighted average rate was approximately 3.2% in 1979 and 1978). 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.

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 ratepayers, such costs do not represent a regular operations cost of the power program and are not included therein. The $627 million in irrigation assistance payments shown as returnable from power revenues 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 $627 million does not include any portion of $21 million of costs allocated to irrigation at six Corps projects located within Oregon 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, 1979 (excluding interest totaling approximately $1,379,000 subsequent to June 1976 which has been charged to expense) was $78.3 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 $50.2 million.

Disposition of the project's costs and final decision as to the repayment obligation are dependent upon Department of 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. In response to a request from Congress, a task force established by the Departments of Interior and Army developed a settlement proposal and submitted it to the Office of Management and Budget (OMB). The OMB did not approve the proposal and suggested instead that the affected federal agencies work with the Tribes to develop a proposal which will encourage their economic development, including a supply of necessary power. It is not currently expected that resolution of this matter will adversely affect FCRPS power revenues.

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 July 1978 three private utilities, Pacific Power & Light Company, Portland General Electric Company and Montana Power Company, who had previously been joined by BPA as defendants, filed cross-claims against BPA. They contend that the BPA preference clause entitles them to power for their domestic and rural customers. Montana Power Company also claims a statutory geographic preference for Federal hydro power produced at Hungry Horse and Libby Dams.

In the opinion of the BPA General Counsel the lawsuits originally filed by the City of Portland and counterclaims filed by the private utilities are without merit. This litigation is being vigorously defended by BPA. The financial effects on FCRPS in the event of adverse decisions in these cases cannot be estimated. During the current session of Congress, legislation was introduced to authorize BPA to develop a regional power program and purchase additional power resources which would enable it to meet the loads of public agencies, direct service industrial customers, and private utilities. This or similar legislation, if enacted, may render moot the City of Portland lawsuits and counter-claims of the private utilities.

Certain other claims, suits and complaints have been filed or are pending against entities of FCRPS, including litigation relating to the installation of additional generating capacity at Bonneville and Libby dams. 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 primarily affect the overall cost of construction projects which will be capitalized and recovered through future power rates.

Note 11. Events Subsequent to Accountants' Report:

In the City of Portland's first suit (See Note 10) the District Court orally granted a motion by the defendants to dismiss the plaintiffs' claims on the ground that the City had not taken the steps necessary to render their claims ripe for court review. Subsequently the court required further briefing on specific issues relating to the motion. Final briefs have been submitted and the matter is pending. The investor-owned utilities' cross claims are also pending. On December 20, 1979, the City moved to amend its complaint for the purpose of supporting the cross claims of Pacific Power & Light Company and Portland General Electric Company, and on December 27, 1979, BPA petitioned the court to deny the City's motion for the reason that the matter has already been determined.

On January 22, 1980, Pacific Power & Light Company filed suit in the United States District Court for Oregon against the Department of Energy and BPA to have the Assistant Secretary's interim rate order of December 3, 1979, declared unlawful and for other relief, including injunctive relief against collection of BPA's new wholesale power rates which were effective December 20, 1979. It is anticipated that other utilities may institute similar litigation. The new rates are expected to increase BPA's annual power revenues by approximately 88 percent. In the opinion of BPA General Counsel, Pacific's suit is without merit.

Schedule A
Federal Columbia River Power System

Schedule of Amount and Allocation of Plant Investment

as of September 30, 1979 (Thousands of Dollars)

		Commercial Power			Irrigation			Nonreimbursable					
Project	Total	Completed Plant	Construction Work in Progress	Total Commercial Power	Returnable from Commercial Power Revenues	Returnable from Other Sources	Total Irrigation	Navigation	Flood Control	Fish and Wildlife	Recreation	Other	Percent of Total Returnable from Commercial Power Revenues
Projects in service:													
Transmission facilities (BPA)	$2,035,393	$1,815,474	$219,919	$2,035,393									100.0%
Albeni Falls (CE)	33,722	32,133		32,133				$ 135	$ 174		$ 1,280		95.3%
Boise (BR)	75,648	5,390	2,597	7,987	$ 13,754	$ 38,563	$ 52,317		15,344				28.7%
Bonneville (CE)	459,118	89,503	325,186	414,689				34,752			935	$ 8,742	90.3%
Chief Joseph (CE)	427,803	424,494		424,494	730		730				357	2,222	99.4%
Columbia Basin (BR)	1,385,499	491,421	297,504	788,925	462,659	83,092	545,751	1,000	47,497	$ 1,800		526	90.3%
Cougar (CE)	60,404	18,408	2	18,410		3,064	3,064	545	38,177			208	30.5%
Detroit-Big Cliff (CE)	66,862	40,572	27	40,599		4,786	4,786	221	20,966			290	60.7%
Dworshak (CE)	334,700	285,383	2	285,385				8,201	32,546		8,568		85.3%
Green Peter-Foster (CE)	90,155	49,660	158	49,818		5,805	5,805	364	30,251		1,856	2,061	55.3%
Hills Creek (CE)	48,968	17,381	66	17,447		4,320	4,320	627	26,302			272	35.6%
Hungry Horse (BR)	101,633	76,945	30	76,975					24,658				75.7%
Ice Harbor (CE)	180,224	130,053	2,181	132,234				45,515			2,475		73.4%
John Day (CE) (a)	525,645	384,768	49	384,817				88,178	14,841		11,399	26,410	73.2%
Libby (CE) (a)	564,661	416,368	27,400	443,768					85,848		2,519	32,526	78.6%
Little Goose (CE) (a)	234,915	176,190	2,134	178,324				49,940			4,047	2,604	75.9%
Lookout Point-Dexter (CE)	97,344	46,188	213	46,401		1,368	1,368	731	48,239		511	94	47.7%
Lost Creek (CE) (a)	147,562	26,870		26,870		1,977	1,977		52,672	24,193	28,159	13,691	18.2%
Lower Granite (CE) (a)	384,160	308,510	2,291	310,801				54,094			11,431	7,834	80.9%
Lower Monumental (CE) (a)	257,290	203,608	2,141	205,749				48,302			2,822	417	80.0%
McNary (CE)	328,136	265,546	2,339	267,885				58,144			2,107		81.6%
Minidoka-Palisades (BR)	141,645	13,733	30	13,763	10,254	53,355	63,609		58,643	21	5,317	292	17.0%
The Dalles (CE)	322,045	276,769	382	277,151				42,790			2,082	22	86.1%
Yakima (BR)	72,387	4,598	4	4,602	10,744	54,979	65,723		671	1,153	238		21.2%
Irrigation assistance at 11 projects having no power generation	77,946				77,946		77,946						100.0%
Plant investment	8,453,865	5,599,965	884,655	6,484,620	576,087	251,309	827,396	433,539	496,829	27,167	86,103	98,211	83.5%
Repayment obligation retained by Columbia Basin Project	2,211	1,352		1,352(b)	859		859						100.0%
Investment in Teton Project (d)	78,308		13,741	13,741	50,228	50	50,278		12,006		2,283		81.7%
	$8,534,384	$5,601,317	$898,396	$6,499,713	$627,174	$251,359	$878,533	$433,539	$508,835	$27,167	$88,386	$98,211(c)	83.5%

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

(a) Projects in service that have tentative cost allocations at September 30, 1979.
(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 $83.7 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 $1,379,000 subsequent to June 1976 which has been charged to expense.

Federal Columbia River Power System

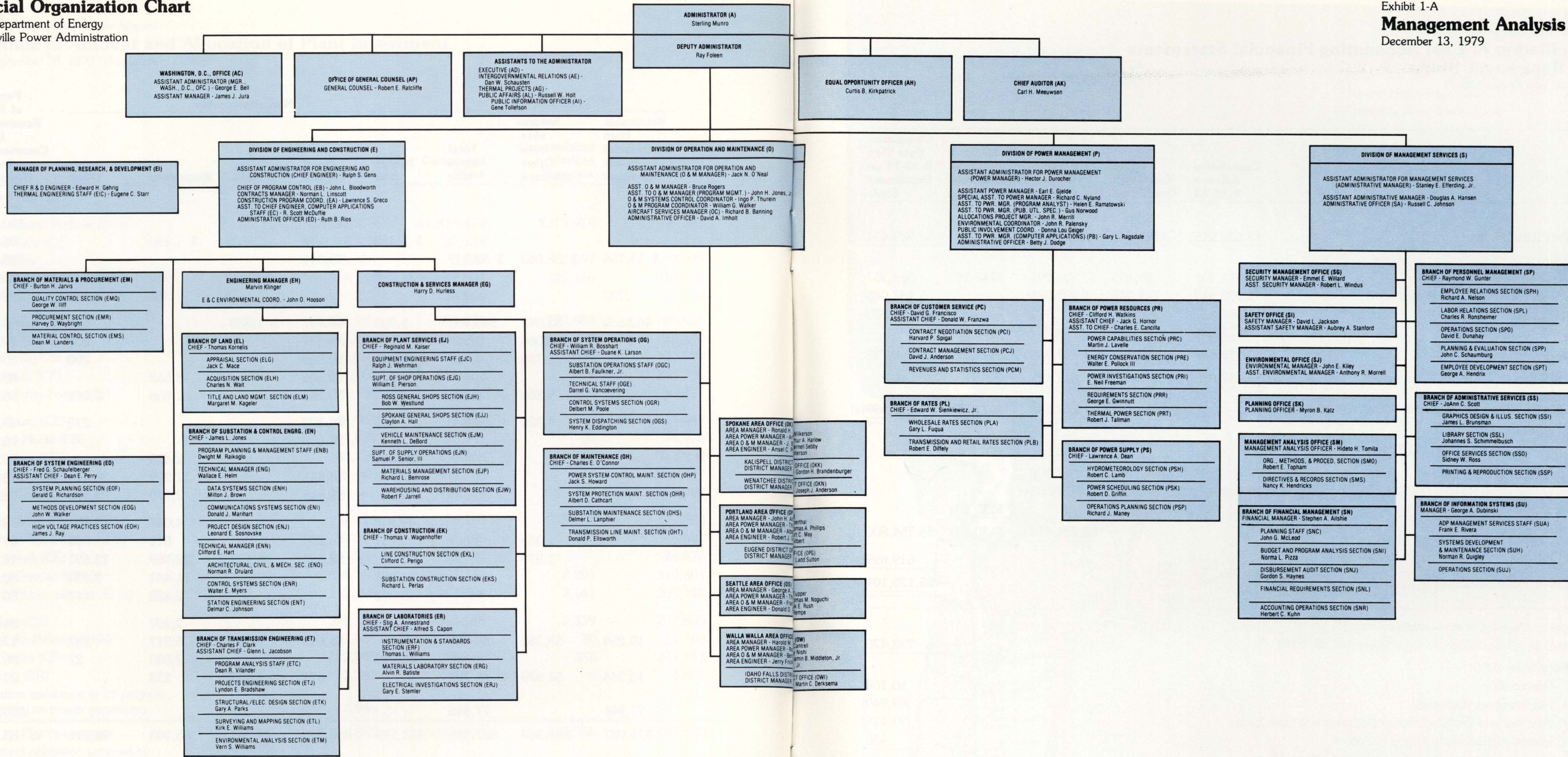
Official Organization Chart

U.S. Department of Energy
Bonneville Power Administration

Exhibit 1-A

Management Analysis Office

December 13, 1979



Reorganization Fiscal Year 1979

During Fiscal Year 1979, several key reorganizations were made in response to changing needs.

Office of the Administrator

In the Administrator's Office the position of Assistant to the Administrator — Public Affairs was reactivated in response to the need for greater public involvement for BPA programs. An Office of Audit also was created within the Office of the Administrator.

Power Management

A new Branch of Rates was established in the Division of Power Management to handle increased rate work. It will be responsible for devising rate strategies that minimize the impact on ratepayers while producing required revenues. BPA was formerly restricted by contract to rate adjustments at 5-year intervals. Removal of that restriction will allow adjustments to be made at more frequent intervals in smaller amounts.

Engineering and Construction

Improved management of the storage and distribution of materials was achieved in the Division of Engineering and Construction by consolidating all of those activities in the Branch of Plant Services. Material storage facilities and activities were transferred from the Branch of Construction to the Branch of Plant Services, where similar warehousing and distribution activities already existed.

Management Services

Major financial management and management information system reorganizations were accomplished in the Division of Management Services. A new Branch of Financial Management was established by consolidating the Budget Office and the Branch of Finance and Accounts. This places all central financial functions under a single manager with the exception of internal audit.

A Branch of Information Systems was formed, in accordance with the recommendations of the consultants Arthur Andersen and Co., by consolidating the Branch of ADP Systems, the Branch of Computer Operations, and the ADP Management Board Staff. This action brings together under the direction of Manager of Information Systems all central functions related to general purpose data processing.

Schedule B
Federal Columbia River Power System

Reconciliation of Cost Accounting Financial Statements to the Repayment Study

For the Fiscal Year Ended 9-30-79
(unaudited)

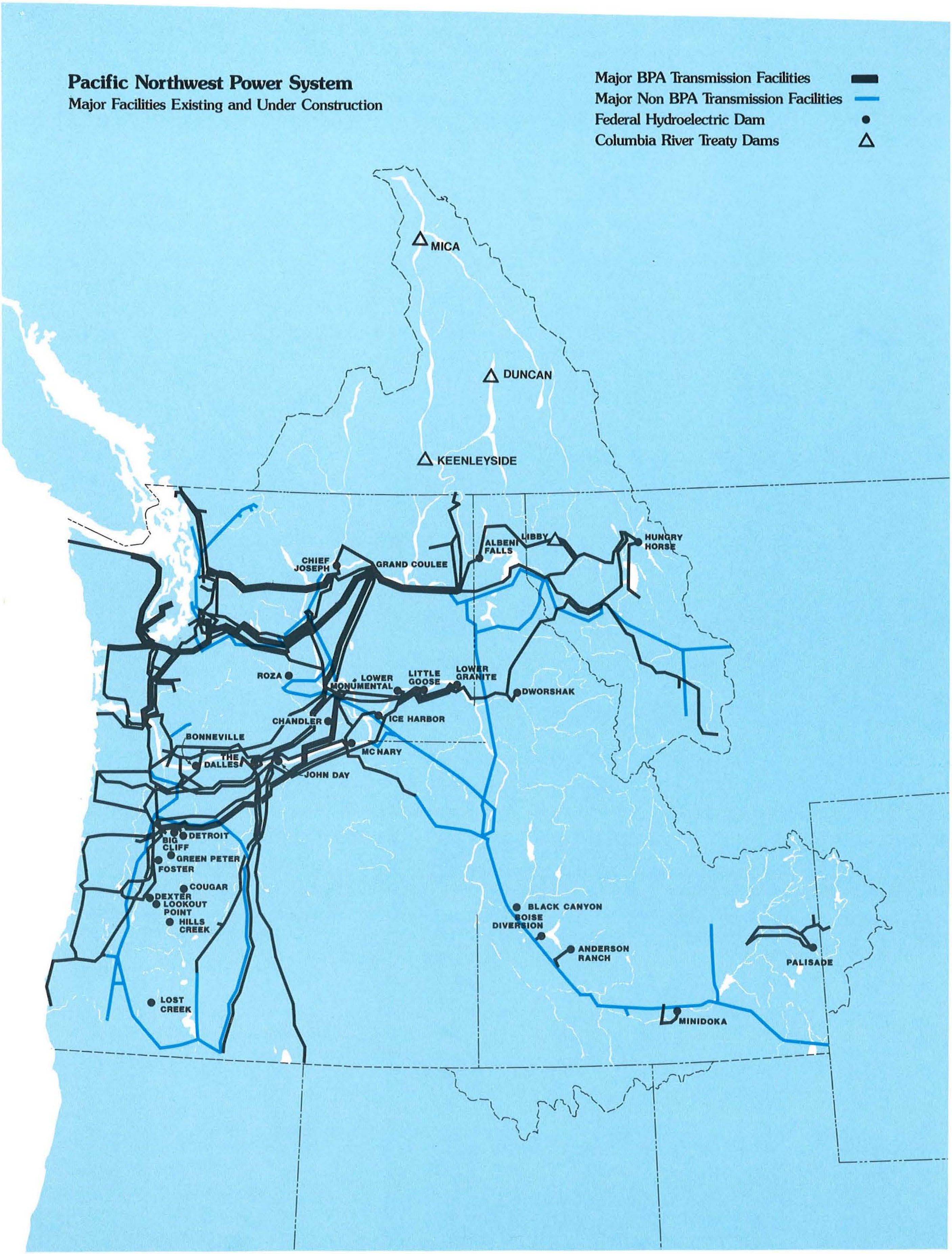
	Cumulative Balance 9-30-78	Fiscal Year 1979 Operations	Cumulative Balance 9-30-79	Cumulative Adj. to Repayment Basis	Cumulative Data Thru 9-30-79 on Repayment Study
			(Thousands of Dollars)		
OPERATING REVENUES	$3,632,915	$296,559	$3,929,474		$3,929,474
EXPENSES:					
Purchase and Exchange Power	311,101	25,195	336,296	$246,861	583,157
Operation and Maintenance Expense	1,073,937	123,148	1,197,085		1,197,085
Interest Expense	1,362,911	168,001	1,530,912	(1,379)	1,529,533
Depreciation	572,888	50,164	623,052	(623,052)	—
Total Expense	**3,320,837**	**366,508**	**3,687,345**	**(377,570)**	**3,309,775**
NET REVENUES	**$ 312,078**	**$(69,949)**	**$ 242,129**		
RECONCILIATION TO CUMULATIVE AMORTIZATION			**$ 242,129**	**$377,570**	**$ 619,699**(a)
PLANT INVESTMENT:					
Completed Plant			$5,599,965		
Retirement Work in Progress			22,802		
Repayment Obligation Retained by Columbia Basic Project (Schedule A)			1,352		
Net Retirements				$130,681	
			$5,624,119	**$130,681**	$5,754,800
Less Amortization					619,699(a)
Unamortized Plant Investment					**$5,135,101**

(a) Changes in Cumulative Amortization:

Cumulative Amortization through September 30, 1978	$ 732,470
Fiscal Year 1979:	
Depreciation	50,164
Net Revenues (Expenses)	(69,949)
Purchase and Exchange Power Adjustment to Cash Basis	(93,416)
Interest Adjustment for Teton Project	430
Amortization for the year	(112,771)
Cumulative Amortization through September 30, 1979	**$ 619,699**

Pacific Northwest Power System

Major Facilities Existing and Under Construction



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U.S. Department of Energy
Bonneville Power Administration
Portland, Oregon