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December 31, 1969

Honorable Walter J. Hickel
Secretary of the Interior
Washington, D.C. 20240

Dear Mr. Secretary:

This is Bonneville Power Administration's thirty-second Annual Report on the Federal Columbia River Power System. The report covers events of fiscal year 1969 and significant developments that have occurred since the fiscal year ended June 30. It has been one of the most eventful periods in Bonneville's history.

Hydro-Thermal Power Program Approval

The capstone event was the approval of the joint Hydro-Thermal Power Program for the Pacific Northwest by President Richard M. Nixon's Administration. Passage of the fiscal year 1970 Public Works Appropriations Bill provided congressional endorsement of the Hydro-Thermal Power Program principle as well. The program will ensure optimum combination of the region's generating and transmission resources—Federal and non-Federal, public and private, existing and planned—to fulfill two key objectives.

First, it will permit timely and orderly development of an adequate and reliable supply of power for the Northwest at the lowest practicable cost. Second, it will meet future power requirements with maximum attention to the importance of preserving environmental quality.

Our commitment to these twin objectives is emphatic. We are determined that each be achieved with the highest concern for the other.

Commitment Policy

A key element in the Hydro-Thermal Power Program is Bonneville's policy of entering into commitments for the sale of power. The ability to make long-range commitments enables Bonneville to engage in meaningful planning. It assures the utilities in the region of the role the Federal system will play and enables them to plan with certainty the development of their own systems. Successful implementation of
the Hydro-Thermal Power Program hinges on a workable BPA commitment policy.

In April, the national Administration formally approved our policy on commitments for the sale of power from Federal hydroelectric projects. Essentially, except for sales or exchanges of peaking capacity from authorized projects, the policy permits us to commit power from Federal projects which are existing or for which construction funds have been appropriated. Approval of this policy provides a solid foundation from which to launch the Hydro-Thermal Power Program.

Cooperation

If there is one characteristic of the Hydro-Thermal Power Program which transcends all others, it is the high degree of cooperation achieved among all 108 participating utilities and between them and BPA. To produce and deliver power most efficiently in the Pacific Northwest requires integrating thermal power with hydro power. Markets must be assured for the output of the largest and most economical thermal plants. Each participant has demonstrated willingness to accept a responsible role in the unique undertaking.
Bulk transmission, peaking capacity, forced outage reserves, fuel displacement energy, and reserves for unanticipated regional load growth are required. These will be Federal responsibilities to be borne jointly by the Army Corps of Engineers, the Bureau of Reclamation, and the Bonneville Power Administration.

Building the largest and most economical thermal plants, timed, sized, and located to meet regional as well as owner needs is the key responsibility to be borne by private and public utilities.

This specialization and division of responsibilities is clearly efficient. But it also increases interdependence and obliges each participant to fulfill its part of the cooperative plan. It is a tribute to the utilities of the Northwest that they, together with Bonneville, have forged a strong and effective mechanism for interutility cooperation, the Joint Power Planning Council.

The region’s utilities, individually and collectively, have also developed productive relationships with Federal and state agencies responsible for protection of the environment. These environmental agencies, in turn, have been involved in the planning of the region’s power system.

Hydro-Thermal Power Program Status

Construction of the first large thermal plant of the Hydro-Thermal Power Program is underway near Centralia, Washington. It is a coal-fired plant being built by Pacific Power and Light Company and The Washington Water Power Company, and shared in by other utilities.

The second large thermal plant in the program is in the advanced planning stage. It will be a nuclear plant built by Portland General Electric Company at Rainier, Oregon, and also shared in by other utilities.

We are discussing plans and marketing arrangements with other utilities for a series of additional thermal plants to be built on schedules closely tied to forecasts of power requirements. The third plant, coal-fired, will be built by Pacific Power and Light Company near Rock Springs, Wyoming. The next four thermal plants will be built by Eugene Water and Electric Board, the Washington Public Power Supply System, Seattle City Light and Snohomish County PUD, and Puget Sound Power and Light Company. Output of each of these plants will be shared with other participating utilities.

At the same time, the Corps of Engineers and the Bureau of Reclamation are proceeding with construction of multipurpose hydro plants (including Libby, Dworshak, Lower Granite, and Little Goose) and with installation of additional generators at existing plants (such as Grand Coulee, The Dalles, John Day, and Lower Monumental).
System Development

During fiscal year 1969, the Federal Columbia River Power System added 1.2 million kilowatts of generating capacity, increasing the number of Federal dams producing electricity to 25 and their combined nameplate rating to more than 8 million kilowatts.

Two of the four Canadian Treaty dams, Duncan and Keenleyside (formerly Arrow), are already operational and contributing to the power system's performance. Construction of the two remaining Treaty projects, Mica Dam in British Columbia and Libby Dam in Montana, is proceeding on schedule.

Bonneville Power Administration built more than 400 miles of 500,000-volt transmission lines during fiscal year 1969, increasing total circuit miles on our system to more than 11,000.

Power Sales and Financial Results

Our energy sales increased 15.8 percent during the fiscal year, reaching a new high of 51.8 billion kilowatt-hours.

Revenues increased 16.4 percent to a new high of $137.3 million. Net revenues, after all expenses including interest on the Federal investment, totaled $28.1 million.

As required by Public Law 89-448, this annual report presents a financial statement on a payout basis for the Federal Columbia River Power System. The statement shows that BPA's present power rate levels will continue to be adequate through 1974; power revenues will repay all costs of generating and transmitting electric energy (including repayment of investment plus interest) and also help repay irrigation costs beyond the ability of water users to repay.

Power Rates

The repayment analysis reflects the new higher interest rate policy for new construction announced October 27, 1969. The analysis was presented to the Federal Power Commission for that agency's review of your decision to maintain present BPA power rates for the 5-year rate period ending December 20, 1974. On December 5, 1969, the FPC approved this decision.

Power Operations

During December 1968 and January 1969, the power system experienced unusually heavy power demands occasioned by exceptionally low temperatures. Every available generator operated to the maximum extent possible. The power situation was aggravated by the temporary unavailability of power from the Hanford project and by delays in Federal generator installation schedules. We imported
as much as 700,000 kilowatts of power into the region and curtailed as much as 400,000 kilowatts of interruptible industrial loads during peak periods on the coldest days. Operations returned to normal in February and continued normal for the balance of the fiscal year.

Accelerated snowmelt and early runoff from a warm spring led to abnormally low streamflows by midsummer at the start of the new fiscal year. A severe shortage of hydro energy developed. By early September 1969, streamflows were at record lows for that time of year.

Exports of surplus energy over the Intertie were stopped. Secondary energy sales to public and private utilities and for interruptible industrial loads ceased. Sales of provisional energy to industry were cut back, first to 70 percent and then to 60 percent of interruptible load.

The situation improved during the last two weeks of September when heavy rains replenished streamflows and reservoirs. Service to secondary and interruptible loads was resumed October 1.

**Intertie**

Throughout fiscal year 1969, the Pacific Northwest-Pacific Southwest Intertie, consisting thus far of two 500-kilovolt alternating-current lines, was undergoing successful break-in operations. The Intertie is now being operated at a top limit of 1,400,000 kilowatts. As operating experience is accumulated and equipment problems eliminated, it is planned to gradually bring the two a-c lines up to their design capability of about 2,000,000 kilowatts.

During the year, the Intertie contributed significantly to the stability of electrical systems in both the Northwest and Southwest. On one occasion, when 1½ million kilowatts being produced at 11 of Grand Coulee’s 18 generator units were suddenly lost, power flow on the Intertie was reversed and a widespread blackout in the Northwest was averted. And during the cold weather spell, the Intertie brought sizable blocks of power to the Northwest.

The Intertie is performing valuable services for the two regions it interconnects. It is enabling the marketing of surplus Northwest energy to California. It enables Northwest utilities to sell Canada’s share of Canadian Treaty power to California. It makes it possible for Northwest industries to maintain production by purchasing energy from California to replace curtailed interruptible deliveries from Bonneville. It permitted importation from California of up to 700,000 kilowatts during the 1968-69 winter cold snap to meet record high Northwest loads. And it tends to speed restoration of system stability following loss of major generation. It is expected that surplus sales on the
Intertie will increase significantly as experience is gained with operations of interconnected power systems.

Meanwhile, construction of America's first—and the world's largest—long-distance, high-voltage direct-current transmission line, which is a key part of the Intertie, proceeded apace. The converter stations at each end of the line are undergoing tests. The 800,000 volt, 846-mile line is now scheduled to carry power commercially between The Dalles Dam on the Columbia River and the City of Los Angeles beginning about March 1970.

**System Control**

The program to automate system control and dispatch, essential for efficient operation of an increasingly complex power system, is moving steadily forward. Adoption of this dramatic new technology is expected to yield substantial improvements in the control of streamflows and electrical operations. By employing high-speed, special-purpose computers to schedule generation and control transmission, the Northwest power system will be taking a giant step towards optimizing power production, assuring that regional power requirements are met with a minimum investment of resources and improving reliability of electric service.

**Power Outlook**

We are approaching a serious power supply situation in the Pacific Northwest over the next five years. Repeated delays in generator unit installation schedules at key Federal hydro projects in the region will result in utility loads outstripping resources during the years 1970-75. The following table shows the resulting deficits.

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<thead>
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<tbody>
<tr>
<td>Loads</td>
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<td>21,472</td>
<td>22,777</td>
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<td>20,992</td>
<td>21,757</td>
<td>22,922</td>
<td>24,840</td>
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<tr>
<td>Deficit</td>
<td>(425)</td>
<td>(480)</td>
<td>(1,020)</td>
<td>(1,154)</td>
<td>(609)</td>
</tr>
</tbody>
</table>

The deficit of 1,154,000 kilowatts shown for 1973-74 is equivalent to more than the combined peak loads of the cities of Tacoma and Eugene. Even with the elimination of interruptible industrial loads, the
1973-74 firm peak deficit will reach 262,000 kilowatts. This means that under certain conditions, we will be short of necessary reserves and it will be necessary to cut off firm loads. We have not yet decided which firm loads will have to be dropped under these circumstances.

The situation is even more alarming than suggested by the table. Any significant delay in installation schedules of Federal generation will compound the seriousness of the problem and force additional firm loads to be cut off under adverse circumstances. Moreover, the table assumes some resources which are highly problematical. For example, because of air pollution problems in the Los Angeles basin, it is now uncertain that Southern California Edison will be able to advance construction of its Huntington Beach thermal plant six months ahead of its own needs. This will deprive the Northwest of 790,000 kilowatts we expected to import over the Intertie in the winter of fiscal year 1974. Without this import, the projected January 1974 peak deficit will approach 2 million kilowatts.

Any combination of adverse events—a harsh winter, unanticipated load growth, delay in installation schedules, unscheduled generator outages, or critical hydro conditions—could leave the region vulnerable to serious power shortages. Makeshift emergency arrangements
to secure power from outside the region are being explored. Whether or not we will be successful in making such arrangements is uncertain.

Much of this bleak short-run outlook stems from the very long lead time required for construction of hydroelectric projects and large modern steamplants. When generator installation schedules are slipped, it becomes difficult or impossible to accelerate construction of alternative resources to meet forecasted loads. Power shortages result.

**Long-Range Outlook**

The Administration's approval of the Northwest Hydro-Thermal Power Program brightens the prospects for meeting regional loads after 1975. Without the Hydro-Thermal Power Program, one of two things would happen. Either (1) the region's forecasted power requirements would not be met or (2) loads would be met but at excessively high costs to society.

By simulating conditions which would prevail under a single ownership, the Hydro-Thermal Power Program not only holds the promise that loads will be met but that they will be met by an efficient power system which closely approximates the ideal model—minimum capital requirements, lowest rates to consumers, and minimum impact on the environment.

**Implementation of Hydro-Thermal Power Program**

Approval of the Hydro-Thermal Power Program will not permit any slackening of effort. Quite the contrary. Although the Program provides the framework in which the region's future power system will develop, implementation will confront us with formidable challenges.

A major problem will be protecting the quality of our environment. As an agency in the Department of the Interior, we recognize our responsibility to safeguard the environment. The utilities of the Northwest are increasingly sensitive to this problem. We are determined that no power facility be developed without careful evaluation of environmental consequences and that effective steps be taken to minimize potential environmental damage.

Another problem of implementation is to ensure that the critical timetable schedules for installation of hydro and thermal generating resources and transmission needed to integrate those resources to serve growing loads are observed. Any serious delay will result in greater power deficits than now anticipated.

The planning of a regional power system is a dynamic process and this too presents problems. Forecasts of loads and resources must be
To meet the power needs of the Northwest, we have achieved enlightened progress—an accord between man and an accommodation with our environment.

Implementation of the Hydro-Thermal Power Program will also require continuation and extension of the high degree of interutility cooperation which has been manifested by the Joint Power Planning Council. Existing cooperative arrangements will have to be maintained and strengthened. Development of additional modes of cooperation will be required to fully integrate the views and interests of other agencies and the public at large.

I would like to add one thought on power supply reliability. We can no longer speak of just regional reliability; instead we must refer to interregional reliability. Disturbances on the Northwest power system can affect electrical service outside the region and vice versa. Utilities in the Western United States must carefully coordinate their planning and operation. This is being done through the Western Systems Coordinating Council.

Budget Restraint

In operating the Federal Columbia River Power System over the past year, we have had to be mindful of two countervailing forces. On the one hand, the Nation has been confronted with serious price inflation which has resulted in the imposition of stringent budgetary constraints on our program. On the other hand, increasing electric power loads of the Pacific Northwest have had to be met by joint cooperative action of Federal and non-Federal entities to achieve minimum environmental damage and an ample and dependable supply of low-cost power. In this setting we have endeavored to strike the appropriate balance between our dual responsibilities—to the national fiscal policy and to the regional power system.

Inauguration of the Hydro-Thermal Power Program does not relieve us of these immediate problems. It does, however, focus our attention on the future. It is the challenge of this program to which we now address ourselves.

Sincerely yours,

H. R. Richmond
Administrator
HYDRO-THERMAL POWER PROGRAM:
A PROGRESS REPORT

The Pacific Northwest's Hydro-Thermal Power Program was officially approved by President Richard M. Nixon's Administration on October 27, 1969. Secretary of the Interior Walter J. Hickel announced "a new accord in power planning between the Federal Government and public and private utilities through greater pooling of all facilities, existing or to be built."

In December 1969, Congress went on record formally endorsing the Hydro-Thermal Power Program principle by passage of the fiscal year 1970 Public Works Appropriations Bill. Language contained in the bill confirmed BPA's authority to acquire some of the output from non-Federally financed thermal generating plants by net billing. Under this arrangement, BPA payment obligations would be liquidated by net billing against amounts due to BPA from thermal plant participants under their other obligations to Bonneville. All net billing arrangements, before they are put into effect, will be subject to approval of the Department of the Interior and to review by the Bureau of the Budget and the congressional appropriations committees.

Secretary Hickel defined the program as a long-range plan to assure low-cost electricity for the Northwest by blending the resources of hydroelectric systems with those of non-Federal thermal generating plants.

Arrangements for the Hydro-Thermal Power Program will be based on agreements among the utilities and Bonneville Power Administration. The output of each thermal generating plant will be shared by a number of utilities, both public and private, with BPA providing reserves, peaking capacity from Federal hydro plants, and most of the high-voltage transmission.

Private and public utilities will build the thermal plants. None will be constructed by the Federal Government. Some of the new thermal plants will be owned jointly by public and private utilities. Others will be wholly publicly or privately owned.

As a key element in the hydro-thermal plan, Bonneville will acquire thermal-generated electricity and combine it with the peaking capacity from the extensive Federal Columbia River Power System to assure low rates for BPA's customers. Secretary Hickel's announcement cleared the way for BPA to participate in the program. The first two thermal plants are underway.

By October 1969, about 10 percent of the work had been completed on Pacific Power & Light and Washington Water Power Companies' 1.4-million kilowatt, coal-fired generating plant. The plant is beginning to rise above the floor of the Hanford Valley five miles northeast of Centralia, Washington.

The first of two 700,000-kilowatt generating units at Centralia is to begin producing electricity in September 1971, and the second a year later.

Under arrangements agreed to during the year, BPA will acquire some of the power from the Centralia plant until 1974 through a net-billing arrangement. The power will be used to help meet loads between 1971 and 1974. Ultimately, 28 percent of the power from the Centralia plant will be distributed to public utilities (Snohomish County PUD, City of Seattle, City of Tacoma, and Grays Harbor County PUD). Beginning in 1982, BPA may obtain the public utilities' share of the plant's output under the net-billing concept. Or, at their option, BPA may wheel this power to the participants' load centers. The remaining 72 percent of Cen-
Australia's output will go to the two sponsors, PP&L and WWP, and to Puget Sound Power & Light Company and Portland General Electric Company.

Meteorological and other testing has begun at the site of the program's second large thermal plant near Rainier, Oregon, where Portland General Electric Company plans to construct a 1.1-million kilowatt generating unit powered with nuclear fuel. Contracts have been let for the power-supply units and for enough nuclear fuel for the first five years of operation. The plant is to come on the line in September 1974.

Portland General Electric Company will own 60 percent of the plant, and Pacific Power & Light Company 10 percent. About 30 percent of the nuclear plant at Rainier will be owned by the Eugene Water & Electric Board, which expects to sell about half of its portion of the output to nine public utilities and cooperatives (City of Canby, Clatskanie PUD, Consumers Power, City of Forest Grove, City of McMinnville, City of Milton-Freewater, Salem Electric, City of Springfield, and Umatilla Electric Cooperative). BPA, in turn, may acquire the power from Eugene and the other nine public utilities through net billing.

Plans for the third thermal plant also took shape during the year. These plans call for a plant to be built in the coal fields near Rock Springs, Wyoming, by Pacific Power & Light Company. It will be 100 percent privately owned, by PP&L and Idaho Power Company. Three 500,000-kilowatt generating units will ultimately give the plant a total capacity of 1.5 million kilowatts, 1 million of which will produce power for utilities in the West Group Area of the Northwest Power Pool. The first unit will serve Wyoming and Idaho loads. The West Group is to get power from the second unit beginning in 1975, and the third in 1979.

Plant No. 4 is scheduled to be built by Eugene Water &
Electric Board. During the past year, Eugene has been investigating sites in southwest Oregon for a large nuclear plant. It is to begin producing electricity in 1976. The City's voters passed a $225 million bond issue in November 1968 to finance the plant. Other participants in the Eugene plant will include PGE and PP&L. About 15 public agency utilities and cooperatives will participate in Eugene's ownership share. This latter group is expected to obtain power from Eugene and deliver it to BPA under the net-billing concept. Tacoma City Light may participate during the first few years of the plant.

Plant No. 5 is scheduled to be built by the Washington Public Power Supply System. WPPSS' present plans provide for construction of a 1-million kilowatt or larger nuclear plant somewhere in southwest Washington. It will be 100 percent publicly owned and it is expected that most of the 104 public agency members of the Joint Power Planning Council will be participants in the plant. Production at the plant would begin in 1978 and the entire output will probably go to BPA under net billing.

Of the next two thermal plants, both of which will probably be nuclear, one is to be jointly sponsored by Seattle City Light and Snohomish County PUD. The other plant would be built by Puget Sound Power & Light Company. Both are expected to come on the line before 1981. Again, other utilities are expected to participate in the ownerships and outputs of these plants.

Plans for this series of thermal generating plants are being coordinated through the Joint Power Planning Council composed of 108 public and private utilities and BPA. The JPPC developed the Hydro-Thermal Power Program as the most economical means of providing future power requirements, recognizing that the cost of power from these plants will be largely determined by location, size, and the time each goes into production. The plants will be built to meet the load growth of the entire region rather than just the requirements of smaller areas served by individual utilities.

To be more specific, under the program BPA will:

- Acquire surplus energy from that share of a plant's
output owned by private utilities under exchange agreements on a short-term withdrawable basis.

- Acquire power from the public utilities' share of thermal generation by net billing.

- Provide peaking capacity, bulk transmission, and generation reserves for forced outages, plus surplus hydro power, when available, for thermal plant fuel displacement. (BPA will provide these services under long-term exchange agreements and will accept off-peak energy or cash in payment.)

- Carry reserves for unanticipated regional load growth, equivalent to one-half-year's growth of utility-type loads, for all participants.

- Strengthen its transmission system to accommodate new generation.

- Use the energy it acquires to serve the load growth of public agencies, renew existing industrial contracts, maintain reserves, and, to the extent possible, provide a modest amount of firm power to industry for future expansion.

- Set up a new class of power (and rate) for industry, subject to the approval of the Federal Power Commission, under which BPA industrial customers would (a) take 25 per cent of their load as nonfirm energy, (b) accept the interruption at any time of one-half their load for up to two hours and thus provide forced-outage reserves for the system, and (c) accept the interruption at any time of all their loads for up to five minutes to maintain system stability.

The Federal Government will continue its program to provide more hydro peaking power. The bulk of this added capacity will be in the form of additional generators installed at existing Federal hydro projects, the cheapest source of peaking power within the region. (A more detailed discussion of future hydro generation appears in this report on page 19.)

On April 21, 1969, the Administration formally approved a policy for the commitment by BPA of power generated at Federal hydroelectric projects. In addition to energy sales, commitments also include wheeling arrangements, provisions for reserves, surplus energy for fuel displacement, and exchange arrangements to supply peaking capacity. The ability of BPA to make long-term commitments is an indispensable ingredient of the Hydro-Thermal Power Program. Without it, neither BPA nor the participating utilities would know what functions each is expected to perform. Long-range power planning would be rendered impossible. And a principal objective of the Hydro-Thermal Power Program—adequate, reliable power to meet regional loads at lowest practicable cost—would be imperiled. In short, a meaningful BPA commitment policy is essential to implement the Hydro-Thermal Power Program.

The approved policy on commitments provides that BPA can commit power from existing Federal hydro projects and from Federal hydro projects for which construction funds have been appropriated. The only exception to this policy would be in the case of con-
tracts such as exchange agreements and net-billing arrangements where commitments can be made further in advance. Under the Hydro-Thermal Power Program, a net-billing arrangement is considered an assured resource available for commitment at the time BPA and the owners of a thermal plant contract for the plant’s construction and the purchase of power.

Conforming to law, the approved BPA commitments policy provides first priority for the power requirements of preference customers. Additional assured Federal capability, after subtracting other BPA firm sales or exchange contracts with private and public utilities and reserves for unanticipated load growth for all utilities, will be made available to electroprocess industries and private utilities. With respect to exports, only energy and peaking capacity which is surplus to the needs of the Pacific Northwest will be sold outside the region. (Details of the approved BPA commitments policy appear as an appendix to this report.)

The Hydro-Thermal Power Program will be implemented through a number of contractual agreements. The various utilities involved and BPA are drafting these contracts in the same atmosphere of cooperation that has marked previous mutual efforts such as the Northwest Power Pool, Coordination Agreement, Canadian Treaty, and Pacific Northwest-Pacific Southwest Intertie.

In addition to providing sufficient reliable power to meet regional power requirements with a minimum investment of resources, another principal objective of the Hydro-Thermal Power Program is to minimize the effect on the environment in meeting future electric power needs. Both objectives are important. And neither will be sacrificed for the other. The substantial versatility of the Hydro-Thermal Power Program, derived from coordinated planning, improves the likelihood that both objectives will be satisfactorily met.

With the Hydro-Thermal Power Program, power will be transmitted at the lowest cost per unit by use of extra-high transmission voltages. This will also mean that given transmission capacity can be achieved with minimum space requirements. The program also contemplates extensive utilization of existing transmission rights-of-way by replacing existing lines with extra-high voltage circuits.

The fact that peaking generator units will be installed primarily at existing hydro powerplants (both Federal and non-Federal) or at plants already under construction means more extensive use of existing plant potential with correspondingly reduced environmental impact. The fact that the Hydro-Thermal Power Program permits construction of the largest feasible thermal powerplants means avoidance of a proliferation of plants to serve growing regional loads. And the fact that thermal plants can be sited to take advantage of the BPA high-voltage transmission network means improved siting flexibility to accommodate environmental problems.

The Joint Power Planning Council established an Environmental Committee in March 1968. The Committee
has since worked closely and cooperatively with Federal and state agencies to define problems, suggest research, and recommend solutions.

BPA is the marketing agent for power from Federal dams in the Northwest and operates the region's main transmission grid. At the same time, of course, BPA is an agency of the Department of the Interior and as such is fully cognizant of its responsibilities to help fulfill the precepts of such legislation as the Federal Water Pollution Control Act, the Water Quality Act, and the Air Quality Act. We participate prominently in power planning sessions for the region and in these meetings and elsewhere we will continue to emphasize the importance of the natural environment and the tremendous obligation upon all power system participants to preserve and protect it.

POWER RATES AND REPAYMENT OF POWER INVESTMENT

Two major actions regarding BPA's wholesale power rates marked 1969 as a year of significance. These were:

1. The decision by the Secretary of the Interior to continue BPA's existing wholesale power rates with no change for the next five years and the approval of that decision by the Federal Power Commission.

2. The Secretary's decision to adopt a new interest rate policy for new Federal power projects.

BPA is required under the Bonneville Project Act to review the adequacy of its power rates at least every five years and to obtain approval of the rates from the Federal Power Commission. BPA power sales contracts permit the rates to be changed only on December 20 of every fifth year. December 20, 1969, was such an adjustment date. It was thus necessary to first determine whether any change in the power rates was warranted, and then obtain FPC approval of the recommended rates for the ensuing 5-year period.

The law requires that BPA set its rates at a level sufficient to bring in enough revenues to pay all Federal
Columbia River Power System expenses and fully repay the Government's investment in the power facilities, with interest, within specified time limitations. BPA must be able to demonstrate that revenues from the rates proposed for approval will be sufficient to meet this objective.

Intensive study was given, therefore, to the revenues BPA could expect to receive from the existing power rates and to projections of power costs to determine whether the rates would continue to be adequate. These studies showed that all power costs could be recovered by existing rates with a comfortable margin.

However, it was also apparent that the cost of interest to the Government had increased substantially in recent years, and that there was reason for concern as to whether the existing policy for establishing the rate of interest to be paid on the Federal investment in power facilities was appropriate in view of current interest costs.

BPA, as well as the other Interior Department power marketing agencies, had been following a policy of paying a rate of interest on each new power project and each year's increment of investment in the transmission system, based upon the average interest rate paid by the Treasury on all outstanding long-term Treasury bonds. This rate had been 3½ percent for the past two years. The policy had been approved by Congress in the authorization of the Grand Coulee Third Powerplant in June 1966.

This policy does not reflect the higher interest rates of recent years, however, because the maximum interest the Treasury is legally permitted to pay on long-term bonds is 4½ percent. The prevailing yield on outstanding long-term Treasury bonds in the money market has exceeded that level—at one time reaching as high as 6½ percent. Thus, no new long-term Treasury bonds have been issued for several years. Short-term Treasury borrowing, which is not encumbered by a 4½ percent ceiling and which now accounts for all of the Government's current borrowing, has also been at a similarly high interest rate. Consequently, it has become more and more apparent that the interest rate policy has not reflected the actual cost to the Government of borrowing money.

This recognition led to the Secretary's decision, which he announced on October 27, 1969, to issue an order establishing a new interest rate policy for the Federal power projects subject to his jurisdiction. The new policy is designed to provide an interest rate for new projects which more closely approximates the actual current interest cost to the Treasury.

Under the new policy, new project construction started in fiscal year 1970 will bear an interest rate of 4½ percent. This basic rate is the same as prescribed by the Water Resources Council for the economic evaluation of proposed new projects. The policy further provides that the interest rate for repayment of new projects started in each fiscal year thereafter shall be adjusted upward or downward from the preceding year's rate by up to one-half percentage point based upon the average yield in the bond market on outstanding long-term Treasury bonds for the preceding 12 months.

Following the Secretary's announcement of the new interest rate policy, BPA prepared and submitted to the FPC an updated repayment study applying the new interest rate policy. This study demonstrated that the existing wholesale power rate level would still continue to be adequate to meet all power costs, including the higher interest rates on future construction, for the next five years.

On December 5, 1969, the Federal Power Commission approved continuance of the existing BPA rates for
The 5-year period extending to December 20, 1974.

The power system repayment study is shown in Table 7 and is also graphically illustrated above. In addition to demonstrating the adequacy of the power rate level to the FPC, this study is also responsive to the requirement for a consolidated Federal Columbia River Power System financial statement contained in Public Law 89-448.

The repayment study demonstrates that BPA's power rates are adequate to provide sufficient revenues to meet the following repayment criteria:

1. Pay all costs of operating and maintaining the power system.
2. Pay the cost of obtaining power through purchase and exchange agreements with other utilities.
3. Pay interest on the unamortized portion of the commercial power investment at the interest rates established for each project.
4. Repay the capital investment allocated to commercial power at the generating projects within 50 years after each project is completed.

5. Repay each increment of capital investment in the transmission system within the average service life of the transmission facilities (currently 45 years).

6. Repay the investment in each replacement of a facility at a generating project or on the transmission system within its service life.

7. Repay the portion of construction costs at Federal reclamation projects which is beyond the repayment ability of the irrigators, and which is assigned for repayment from commercial power revenues, within the same overall period available to the irrigation water users for making their payments. These periods range from 40 to 66 years with 60 years being applicable to most of the irrigation assistance.

(Although power rate levels are set on the basis of meeting repayment requirements as described above, BPA is also required to keep books on a cost accounting basis to comply with accounting policies prescribed by the Comptroller General. Therefore, financial results for fiscal year 1969 on the cost accounting basis are presented in another part of this report under "Financial Results.")
GENERATION

During fiscal year 1969, the Federal Columbia River Power System added 1,235,000 kilowatts of generating capacity.

This additional capacity consists of 135,000 kilowatts at Lower Monumental Dam, the first eight units totaling 1,080,000 kilowatts at John Day Dam, and 20,000 kilowatts at Foster Dam.

There are now 25 Federal dams producing electricity in the Pacific Northwest. These Federal hydro projects are built and operated by the Bureau of Reclamation or the U.S. Army Corps of Engineers. They have an installed capacity of 8,074,150 kilowatts.

The non-Federal generating plants in the region have a total installed capacity of 10,680,822 kilowatts. Included in this amount are 800,000 kilowatts at Hanford Generating Plant and 437,819 kilowatts at old steamplants.

Thus, the combined generating capacity at all Northwest plants stands now at 18,754,972 kilowatts.

Federal capacity under construction totals 7,685,000 kilowatts. This includes six Federal dams — Libby, Little Goose, Lower Granite, Dworshak, Lost Creek, and Teton — which will have a combined nameplate rating of 1,695,000 kilowatts. The large balance of the capacity under construction is being installed at existing projects.

These additional generators — to be added at The Dalles, Grand Coulee, John Day, and Lower Monumental — will have a combined capacity of 5,990,000 kilowatts. This figure includes 3,600,000 kilowatts for the Third Powerhouse and 97,000 kilowatts for two pump-generator units, all of which are in initial phases of construction at Grand Coulee. If Congress so authorizes, the number of turbine-generator units in the Third Powerhouse may be increased and its capacity raised to 7.2 million kilowatts. Grand Coulee would then have a total capacity of about 10 million kilowatts, more than any existing dam in the world.
Between now and 1980, public and private non-Federal utilities plan to add 11,129,370 kilowatts of generating capacity in the Northwest. This figure includes 7,906,000 kilowatts of capacity to be installed at thermal plants, principally nuclear.

Northwest utilities estimate that electric power requirements in the region will almost triple in the next 20 years.

The region is running out of feasible hydro sites, although a few remain which can be developed. Turbine-generators may be added at other projects.

Between 1974 and 1991, the Northwest will require steamplants to meet the base load at an average of more than one 1-million-kilowatt plant a year. The amount of additional new steam generating capacity required each year will increase as regional loads grow. The Federal Columbia River Power System will support these plants with peaking capacity, reserves, and transmission capacity—via the BPA grid.

Congress has authorized two Federal hydro projects not yet under construction: Asotin, with a nameplate rating of 540,000 kilowatts, and Strube, with a rating of 4,500 kilowatts. Authorized additions at Bonneville, Chief Joseph, and Ice Harbor Dams could add another 1,702,000 kilowatts to the system in the next 10 years.
TRANSMISSION CONSTRUCTION

During fiscal 1969, BPA added 507 circuit miles to its system of transmission lines. Four hundred two miles were 500,000-volt lines, the highest voltage on the system until the first direct-current 800,000-volt Inter-tie line is completed in 1970.

This raised the total number of circuit miles on the system to 11,151, and the total mileage of 500,000-volt lines to 1,315.

System transformer capacity as of June 30 totaled 28,401,062 kilovolt-amperes.

Present plans call for another 1,566 miles of 500,000-volt lines, partly to strengthen service to western Montana and to integrate the output of new dams on the Lower Snake River. BPA is already operating one of the largest 500,000-volt grids in the United States. The use of these large lines requires significantly less land for rights-of-way per unit of power transmitted.

A key line among those to be constructed is a 123-mile 500,000-volt line from Chief Joseph Dam in north central Washington to Monroe Substation northeast of Seattle. When this line is energized, it will provide capacity to serve growing loads in western Washington at a time when loads are reaching critically heavy levels. Part of the electricity ultimately to be moved over this line will come from the new Third Powerhouse at Grand Coulee Dam.

BPA's construction plans are meshed with those for new large thermal generating plants now under construction or projected for the future. Because these thermal units will eventually supply base power while hydro plants supply peaking power, new transmission must be planned accordingly.

For example, the 116-mile 500,000-volt Raver-Paul-Allston line is being built to connect the Seattle and Portland areas. This line is a main link in the 500,000-volt grid. It will also integrate into the grid power from the coal-fired generating plant under construction near Centralia by the Pacific Power & Light and Washington Water Power Companies.
SALES

Energy sales in fiscal 1969 increased 15.8 percent over the previous year and reached a new high of 51.8 billion kilowatt-hours.

The amount of power used by the aluminum industry increased 19 percent, or 3 billion kilowatt-hours. The 20.2 billion kilowatt-hours sold to the aluminum industry in fiscal 1969 accounted for 39 percent of all BPA’s energy sales. Most of the increase was used by new potlines at the Anaconda, Intalco, and Reynolds plants.

Publicly owned utilities bought 18.9 billion kilowatt-hours in the fiscal year; 36.5 percent of the energy sold.

Investor-owned utilities purchased 7.2 billion kilowatt-hours (13.9 percent), Federal agencies 1.6 billion kilowatt-hours (3.1 percent), and industries other than aluminum 2.4 billion kilowatt-hours (4.6 percent). One and one-half billion kilowatt-hours (2.9 percent) were sold outside the Pacific Northwest.

Power sales brought an average of 2.39 mills per kilowatt-hour, exclusive of capacity sales and other revenues.

By class of customer, the average revenue per kilowatt-hour was: aluminum industry 2.03 mills, other industries 2.22 mills, investor-owned utilities 2.21 mills, public agencies 2.92 mills, Federal agencies 2.44 mills, and sales of surplus energy outside the Pacific Northwest 2 mills.

Eighty-nine out of the 104 public agencies served by Bonneville buy all of their power, including peak needs, from BPA. This results in a slightly higher-than-average cost of energy, as compared with the industrial and investor-owned purchasers.

FINANCIAL RESULTS

From a cost accounting standpoint, fiscal year 1969 was one of the best years in BPA’s history.

Revenues increased $19 million, or 16.4 percent, over fiscal 1968 and totaled $137.3 million.

System costs were up $10.1 million, or 10.2 percent.

Net revenues after all expenses, including operation, maintenance, purchase and exchange, depreciation, and interest, totaled $28.1 million. Net revenues accumulated since the beginning of operations now exceed $322 million.

Revenues from the sale of power outstripped estimates by $7 million. The estimates, of course, were based on normal weather conditions. However, severe cold weather in December and January boosted the demand for power to a new high for BPA. As a result, sales to publicly owned utilities were 13.5 percent higher than the year before and were well above the public utilities’ normal rate of increase.

A gain of $6.7 million in revenues from the aluminum industry was the largest for any group of customers. It reflects a new record in aluminum production for the Northwest. Total sales to this group were $40.8 million.

The Pacific Inter tie brought BPA $3.1 million from the sale of energy surplus to Northwest needs and $1 million for wheeling. For operating reasons and by agreement of utilities using the lines, capacity on the intertie was limited to 400 megawatts early in the fiscal year, but was raised to 800 megawatts on September 12, 1968, and to 1,400 megawatts April 1, 1969. These capacity limitations restricted potential Intertie sales.

Total system revenues included $3 million received directly by generating projects for headwater benefits and irrigation pumping power.

Each year BPA pays in full the costs for operation
and maintenance, interest, and the purchase and exchange of power. The balance of its revenues is used to pay back that portion of the Government's investment allocated to power facilities in the Federal Columbia River Power System. This sum was $47.3 million in fiscal year 1969.

Cost increases were moderate. The largest, for interest, was up $5.7 million. This increase stemmed mainly from the addition of $200 million for power facilities at John Day Dam which became part of the system early in the fiscal year. John Day also contributed to an increase in operation and maintenance costs. Additional details on revenues and costs for the power system as compared with last year are shown in Table 6. The chart on this page shows where revenues came from and how they were applied.

Table 8 contains an account of the trends in revenues by class of customer for the years 1960 through 1969. This was a decade of consistent growth. For example, sales to the aluminum industry for fiscal 1969 are 134 percent greater than for 1960. The sales to public utilities are up 95 percent.

Since the beginning of operations in fiscal year 1939, BPA has returned $1,623,100,000 in revenues to the U.S. Treasury. Of this total, $575,059,000 has gone to repay the capital investment in the power system and $551,139,000 to pay interest costs. Thus, 69 percent of our revenues, or more than $1.1 billion, has been returned to the U.S. Treasury to pay the debt incurred to finance the power system. The remaining 31 percent, $496,902,000, has paid for operation, maintenance, and power purchased.

THE OPERATING YEAR AND ITS PROBLEMS

BPA encountered severe operating conditions during and after fiscal year 1969. Despite adversities, the system performed well although there were times when service reliability was marginal.

During the last few days of December 1968, one of the most severe outbreaks of winter weather in Northwest history invaded the Pacific Northwest region. On December 30, average temperatures for major load centers were the lowest of any December day in recorded history. Demand for power soared to record peaks. Northwest powerplants were running at the maximum capacity permitted by available water. Temperatures remained abnormally low and demand for power high during January, especially the period from January 20 to 29. In addition, the Hanford plant was inoperative during this period, further reducing generating capability of the system by 800,000 kilowatts. The power situation was aggravated still further by delays in Federal generator schedules at Lower Monumental and John Day Dams.

Despite maximum plant output and streamflows which ranged near or above median, it was necessary, in order to meet firm loads, to import power from outside the region and to curtail up to 400 megawatts of interruptible industrial loads. This was the first time since 1957 that actual load curtailments were necessary because there was insufficient power available from other utilities to displace curtailed interruptible loads.

Were it not for the Intertie over which energy was imported from California, reaching a maximum of 700,000 kilowatts, BPA would have had to curtail additional interruptible sales to industry as well as some of its modified firm power sales to industry. Power was also imported from the Missouri Basin, eastern Montana, and Utah.

Fortunately, the severe weather eased and after February 1 we began once again to carry all interruptible loads through the periods of peak demand.

Compounding the seriousness of the region's chronic shortage of peak power reserves was a scheduled draft of the Grand Coulee reservoir later in the year. The reservoir was drafted down to 38 feet below its normal bottom elevation to accommodate Third Powerplant construction. The reservoir had to reach this low level by April 1, 1969, and it had to be held at or below this elevation for a month-and-a-half. While the additional draft below normal bottom elevation increased the energy capability at Grand Coulee and at downstream plants, it greatly reduced the peaking capability at Grand Coulee. This caused the power situation to remain tight until mid-May. To compensate for this reduced peaking capability, we made arrangements with the Atomic Energy Commission to avoid refueling shutdowns of the Hanford steamplant during the deep draft period. Our planning also incorporated the use of Keenleyside (Arrow) Dam storage made possible by the Canadian Treaty.

Accelerated snowmelt and early runoff from a warm spring led to abnormally low streamflows by midsummer. A severe shortage of hydro energy for secondary loads developed in late July 1969 as a result of exceptionally low flows on the Columbia River. The drop in streamflows continued throughout August, falling below critical levels, and by early September had reached record minimums for that time of year.

Export of surplus energy over the Intertie to California
utilities was stopped July 25. Secondary energy sales to private utilities and for interruptible industrial loads were discontinued July 31 (although interruptible industrial loads were served with provisional energy). Secondary sales to public agencies were curtailed August 4. By August 21, BPA was compelled to cut back deliveries of provisional energy to industry by 30 percent. As a result, these customers purchased higher cost power from outside the region rather than curtail production. The cutback in provisional energy was increased to 40 percent early in September.

Substantial rainfall during the last two weeks of September increased streamflows above median levels and reservoirs recovered to above rule curves. Service to secondary and interruptible loads was resumed October 1, 1969.

The Northwest power situation was aggravated during fiscal year 1969 by a shortage of reserve generators. The Federal Columbia River Power System did not have all the reserves it needed because of delays in installing generators at two projects. This cut our
peaking capacity by 776,000 kilowatts. (Three units capable of producing 466,000 kilowatts at Lower Monumental Dam had been delayed from December 1967 and were not on the line until June 1969. And only five units instead of seven were ready in January at John Day, reducing the capacity of that plant from 1,085,000 to 775,000 kilowatts.)

Most of our customers received reliable service during fiscal 1969. However, some industrial customers were sometimes an exception. They were dropped occasionally to protect against area blackouts. This was done automatically by relays which open preselected circuits when certain emergency conditions occur.

Cutting off firm loads to maintain service to other customers is an expediency and reflects less than adequate reliability. We will be forced to continue to cut firm loads during unusual conditions because the construction of new lines that would give us adequate capacity for reliable operations has not kept pace with the growth of loads.

A number of equipment failures and operating problems during the year indicated our preventive maintenance program also has slipped below acceptable standards. Consequences so far have been minor. Nevertheless, it is apparent we have been handicapped in attempting to achieve satisfactory maintenance standards by not having enough personnel to accomplish all the work that should have been done.

The strong electrical ties created with other regions proved to be a boon, especially to the Northwest, and helped us avert at least one major blackout when newly installed equipment was being tested near Grand Coulee Dam. On August 7, 1969, a relay operated inadvertently, causing other relays to trip 11 generators at the dam which had been producing 1,250,000 kilowatts of electricity. As the machines dropped off the line, the flow of power over the Intertie reversed. The Intertie lines, which had been carrying 480,000 kilowatts south, began bringing 325,000 kilowatts north. An industrial load at Spokane was temporarily dropped under the load-shedding scheme. Reserve generators in the Northwest picked up the balance of the load. The system then returned to normal.

The Intertie supported California systems during similar incidents, when those systems suddenly lost the production of large steam units with capacities of up to 750,000 kilowatts.

In addition to our good experience with the Intertie, it should be noted that at 9:05 a.m., October 20, 1969, the Hanford nuclear generating plant passed the production mark of 10 billion kilowatt-hours. It was the first U.S. nuclear plant to reach this mark.

CANADIAN TREATY

The first two dams built under terms of the Columbia River Treaty with Canada have been operating successfully for some time. Construction on the two remaining dams is well underway.

On June 9, 1969, British Columbia’s Prime Minister W. A. C. Bennett presided at the dedication of Arrow Dam five miles above Castlegar on the Columbia River. He announced then that the dam henceforth would be known as the Hugh Keenleyside Dam in honor of the man who was charged with its successful construction. For Dr. Keenleyside the dedication was his last official ceremony before retiring as Co-Chairman of British Columbia Hydro and Power Authority.

The Canadians completed both Keenleyside and Duncan Dams ahead of schedule. Keenleyside was de-
clared operational on October 10, 1968, six months ahead of schedule, and Duncan on July 31, 1967, eight months early.

Work is now proceeding on Mica Dam in British Columbia and Libby Dam in Montana.

Giant strides have been made on the enormous task of placing 42 million cubic yards of fill material required for Mica. When completed by the spring of 1973, Mica, an earth and rockfill structure, will rise 800 feet above bedrock and will have a crest 2,600 feet long.

The Columbia has been diverted around the Mica site through two 3,000-foot tunnels so that the dam can be built on a dry riverbed. The tunnels took two years to build and were ready in 1967.

By early fall 1969, about 8.6 million cubic yards of fill had been dumped in place by a fleet of fifty huge trucks. The construction of a 1,950-foot spillway on the left abutment is well underway. Workmen in September began pouring some 60,000 cubic yards of concrete to line the spillway, which is to be finished in 1971.

The reservoir behind Mica will create a new lake extending 80 miles upstream. One arm of the lake will run 55 miles up the Canoe River Valley.

Libby Dam, which the Corps of Engineers is building in the United States under the Treaty, is now more than 50 percent complete. Libby, 420 feet high and 3,055 feet long, will create a lake extending 90 miles up the Kootenay River in western Montana and southeast British Columbia. The dam will back water 42 miles into Canada. Libby is to begin generating electricity in 1974.

Duncan Dam added 1.4 million acre-feet of usable storage, and Keenleyside 7.1 million acre-feet. Mica will add 7 million acre-feet initially and Libby 5 million acre-feet. This will double the usable storage capacity on the Columbia and its tributaries. The Treaty provides for 15.5 million acre-feet of storage in Canada, of which 8.5 million acre-feet will be usable for flood control.

The four Treaty projects together with other hydro plants on the river will make it possible to control a flood as great as any man has observed on the Columbia since he began to measure the river’s flow before the turn of the century.

Water released from the Canadian projects will increase the dependable capacity at 11 U.S. dams downstream by 2.8 million kilowatts. The additional power produced with this capacity is being shared equally by Canada and the United States. Canada has sold her share to purchasers in the United States for 30 years.
CONTROL & DISPATCH

In 1967, BPA launched a program to prepare the power system to meet the anticipated rigorous demands of the region for dependable electric power. We recognized then that the growing complexities of the far-flung power transmission system were outstripping man's ability to respond to system conditions within tolerable time limits. We knew we would have to turn to high-speed, special-purpose computers which could quickly detect impending trouble and react with split-second timing to initiate corrective action. We also knew we would have to develop new computer programs which would optimize our use of power resources.

To take advantage of the most advanced skills and the highest available technology, we secured the assistance of North American-Rockwell Corporation, prime contractors of the Apollo space program. It was anticipated that spin-off knowledge gained from the aerospace program would find successful application in the electric power field.

This new technology will come to fruition in the new System Control Center at Bonneville's Ross Substation (Vancouver, Washington). Experience and technology from the NASA mission control center, from advanced research by BPA consultants, including universities, and from our own staff of engineers, mathematicians, and computer specialists have been applied to design a plan for a new control center adequate to handle system problems and growth as foreseen for the next twenty years.

The Advanced Control and Dispatch program will provide new techniques that will give us better control of electrical operations and greater system stability. We are compressing margins for error allowed in the past. We are gaining greater control over streamflows by refining the rough approximations of earlier methods. Thus, we are achieving more efficient, economical electrical operations and squeezing more kilowatts, and hence more revenues, out of streamflows.

In many ways the program is a push into the unknown. Many of the methods and some of the equipment required are still in the developmental stage.

The cornerstone of this program will be the construction, by 1973, of the new System Control Center at Ross. The new building is expected to cost about $5 million. It will house sophisticated special-purpose computers and data-storage banks. Information will flow automatically into these machines from power-
houses, substations, and hydrometeorological stations. The control equipment will be able to act on information as it is received or forward it for display so it can be used by men operating the system. In turn, this will lead to more precise control over such system elements as generation, transmission line loadings, and bus-voltage levels.

Engineers and programmers are already developing the special purpose computer program ("software") that will assist dispatchers to perform scheduling, arrange outages for construction or maintenance work, achieve system stability, monitor operations, and expedite service restoration in emergencies.

Facilities for the remote control of substations will be centralized at Ross and computer-directed. The center will control BPA's 500,000-volt and most of the 230,000-volt transmission system. The subtransmission system west of the Cascades will also be controlled from Ross. Another control center, to be located near Pasco, Washington, will control the east subtransmission system and serve as a backup for critical functions performed at and controlled from Ross.

We are modifying our present control center at Portland to prepare for the transition to a more automated system. A special-purpose computer has been installed and is undergoing tests. We have also installed prototype displays for the dispatchers, including an animated wall-type diagram of the Pacific Northwest-Pacific Southwest Intertie system, and a computer-driven color cathode-ray tube display console.

The Advance Control and Dispatch program will culminate a major effort to extract the greatest return from the investment in the Federal Columbia River Power System by development and application of the most modern power system control technology.

INTERTIE CONSTRUCTION

Soon after this report is published, the United States' first, and the world's largest, high-voltage direct-current line will go into commercial operation. The terminal equipment and the 800,000-volt line have been undergoing final tests.

The line's northern terminal, Celilo Converter Station, stands on a bare hill above the Columbia River near The Dalles, Oregon. The line itself stretches 853 miles across Oregon, Nevada, and California. It ends at Sylmar Converter Station, near Los Angeles.

BPA built the Celilo terminal and the line across Oregon to the Nevada border. The City of Los Angeles constructed the line from there south, plus Sylmar, and has shared the costs and ownership equally with the Southern California Edison Company.

The direct-current line will be the third of four large lines included in the original concept of the Pacific Intertie. Two 500,000-volt alternating-current lines are in operation. The fourth line, an 820-mile, 800,000-volt direct-current transmission line, to operate between Celilo and a terminal near Hoover Dam has been postponed until 1977 or later.

The Intertie carries power both north and south and has improved the stability of electrical systems in the Pacific Northwest and the Southwest. The Northwest has received substantial revenues from the sale of secondary power surplus to the region's needs.

These exchanges of power and secondary power revenues will increase after the first d-c line goes into operation. Celilo will convert a-c power from Northwest dams to d-c power, sending it south. Sylmar will convert the power back to a-c and dispatch it to consumers in the Southwest. When power flows north over...
the line, the conversion roles of the two terminals will be reversed.

When the Intertie's two a-c lines were completed, the first in May 1968 and the second in December 1968, the capacity of the lines was limited to 400,000 kilowatts. This was due to a lack of generating capacity and backup lines. As we began to overcome these deficiencies and accumulate operating experience, the Intertie's capacity was expanded to 800,000 kilowatts. New generation at John Day Dam has since made it possible to boost this capacity to 1.4 million kilowatts. Ultimately, the two a-c lines will carry 2 million kilowatts and the d-c line 1.4 million kilowatts.

Thus, we have reached the point in the development of transmission technology when two major regional systems will be linked with both a-c and d-c lines. It will mark the realization of a dream born more than 30 years ago.

Surplus Northwest power can now be transmitted to the Southwest to meet requirements that would otherwise be met with power from generating plants burning fossil fuels. The Intertie results in the better use of renewable resources in the West and the conservation of exhaustible fuels.

Meanwhile, d-c's importance looms larger, for researchers in this country and abroad are perfecting solid-state rectifiers that may displace the mercury arc valves.

The two a-c lines are proving invaluable assets for both the Pacific Northwest and the Pacific Southwest. Over six billion kilowatt-hours of energy were delivered over the Intertie to California during calendar year 1969. About two-thirds was Canadian Entitlement energy, the disposition of which makes implementation of the Treaty possible. Most of the balance was surplus energy.

The Intertie also served other valuable functions. Periods of low streamflow in the Northwest in the fall of 1968 and again in the fall of 1969 required Bonneville to curtail interruptible deliveries to industries we serve. By using energy purchased from California over the Intertie, these industries were able to continue operations.

The Intertie was also instrumental in permitting Bonneville and Northwest utilities to meet the record high loads which the Northwest experienced during the cold spell which gripped the region in late December 1968 and January 1969. Northwest resources loaded to capacity were inadequate to meet loads. Substantial power imports from California over the Intertie enabled Northwest firm utility and industrial loads to be met without disruption.

Finally, by making some of the power resources of one region available to serve loads in another region, the Intertie assisted in maintaining power system stability in both the Northwest and in California. The two regions have been enabled to exchange energy and capacity to assist one another in emergencies.
TABLES
### TABLE 1
**ELECTRIC ENERGY SALES TO CUSTOMERS OF THE BONNIEVILLE POWER ADMINISTRATION**

**Fiscal Year Ended June 30, 1969**

<table>
<thead>
<tr>
<th>Customer</th>
<th>Energy Delivered (1,000 KWH)</th>
<th>Revenue from Sales of Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower Valley Power &amp; Light</td>
<td>10,481</td>
<td>$3,452</td>
</tr>
<tr>
<td>Methow Electric Corp.</td>
<td>4,167</td>
<td>1,356</td>
</tr>
<tr>
<td>Methow Valley Electric Co-op</td>
<td>24</td>
<td>166</td>
</tr>
<tr>
<td>Nez Perce Electric Co-op</td>
<td>34,011</td>
<td>185,300</td>
</tr>
<tr>
<td>Northern Idaho Electric Co-op</td>
<td>97,945</td>
<td>679,786</td>
</tr>
<tr>
<td>Oregon Power &amp; Light Co.</td>
<td>1,425</td>
<td>42,503</td>
</tr>
<tr>
<td>Pacific Power Co.</td>
<td>7,575</td>
<td>7,575</td>
</tr>
<tr>
<td>Pacific Power &amp; Light Co.</td>
<td>10,493</td>
<td>300,348</td>
</tr>
<tr>
<td>Pearson Electric Co-op</td>
<td>21,066</td>
<td>324,985</td>
</tr>
<tr>
<td>Pepsi Co.</td>
<td>7,846</td>
<td>26,246</td>
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<tr>
<td>Pringle Valley Electric Co-op</td>
<td>34,012</td>
<td>135,617</td>
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<tr>
<td>Public Service Co.</td>
<td>14,916</td>
<td>82,323</td>
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<tr>
<td>Quincy Electric Co-op</td>
<td>4,960</td>
<td>42,723</td>
</tr>
<tr>
<td>Rhododendron Electric Co-op</td>
<td>42,886</td>
<td>42,886</td>
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<tr>
<td>South Side Light Co.</td>
<td>50,004</td>
<td>200,097</td>
</tr>
<tr>
<td>Tri-Cities Electric Co-op</td>
<td>8,440</td>
<td>31,572</td>
</tr>
<tr>
<td>Tuft Electric</td>
<td>1,071</td>
<td>1,071</td>
</tr>
<tr>
<td>Unicoil Electric Coop</td>
<td>101,605</td>
<td>3,648,602</td>
</tr>
<tr>
<td>Utility Light &amp; Power Co.</td>
<td>109,124</td>
<td>62,370</td>
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<tr>
<td>Vancouver Electric Co-op</td>
<td>19,402</td>
<td>180,263</td>
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<tr>
<td>West Oregon Electric Co-op</td>
<td>60,010</td>
<td>269,223</td>
</tr>
<tr>
<td>West Oregon Power Co-op</td>
<td>204,310</td>
<td>125,200</td>
</tr>
</tbody>
</table>

**Total Cooperatives (16)** | 2,939,755 | $9,873,990

**Total Publicly Owned Utilities** | 18,909,075 | $55,293,202

<table>
<thead>
<tr>
<th>Company</th>
<th>Energy Delivered (1,000 KWH)</th>
<th>Revenue from Sales of Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>California Pacific Utilities</td>
<td>29,417</td>
<td>63,889</td>
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<tr>
<td>Idaho Power Co.</td>
<td>123,984</td>
<td>286,540</td>
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<tr>
<td>Montana Power Co.</td>
<td>150,745</td>
<td>137,685</td>
</tr>
<tr>
<td>Pacific Power &amp; Light Co.</td>
<td>23,515</td>
<td>23,515</td>
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<tr>
<td>Portland General Electric Co.</td>
<td>3,330,727</td>
<td>6,939,926</td>
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<tr>
<td>Portland Street Light Co.</td>
<td>41,966</td>
<td>101,189</td>
</tr>
<tr>
<td>Utah Power Co.</td>
<td>10,000</td>
<td>10,000</td>
</tr>
<tr>
<td>Washington Water Power Co.</td>
<td>286,008</td>
<td>432,008</td>
</tr>
</tbody>
</table>

**Total Privately Owned Utilities (19)** | 7,186,071 | $64,592,516

**Inductors (1)** | 1,090,076 | 4,270,416

**Aluminum Co. of America** | 2,988,524 | $3,648,602

**Vista Power Plant** | 1,060,369 | 7,600,000

**American Aluminum Co.** | 4,167 | 4,167

**Harry Andersen** | 1,597,072 | 7,600,000

**Koenig Aluminum Corp.** | 1,310,673 | 7,600,000

**Korean Aluminum & Chemical Co.** | 1,400,000 | 7,600,000

**Spokane Regional Plant** | 3,069,201 | 7,600,000

**Spokane Electric Mfg.** | 4,221,751 | 7,600,000

**Tucson Public Service** | 1,200,000 | 7,600,000

**Techno-Medics** | 2,926,641 | 4,246,713

**Tricounty Electric** | 1,546,404 | 5,063,327

**Other Inductors** | 4,221,751 | 7,600,000

**Commercial Co.** | 290,027 | 4,000,000

**Cessna Aviation Inc.** | 11,000 | 2,980,000

**Cochran Electric Co.** | 10,000 | 2,980,000

**Georgia Power Co.** | 10,000 | 2,980,000

**Hawthorne Electric Co-op** | 10,000 | 2,980,000

**Hernando Electric Co-op** | 10,000 | 2,980,000

**K.T. Resources, Incorporated** | 4,221,751 | 7,600,000

**Pacific Coastlight & Supply Co.** | 4,221,751 | 7,600,000

**Pomona Corp.** | 4,221,751 | 7,600,000

**Southern California Edison Co.** | 4,221,751 | 7,600,000

**Union Central Corp., N&W Div.** | 4,221,751 | 7,600,000

**Total Inductors (22)** | 37,147,018 | $53,650,873

**OUTSIDE NORTHWEST AREA**

<table>
<thead>
<tr>
<th>Company</th>
<th>Energy Delivered (1,000 KWH)</th>
<th>Revenue from Sales of Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>British Columbia Hydro &amp; Power Authority</td>
<td>136</td>
<td>250</td>
</tr>
<tr>
<td>Seattle Electric Utility District</td>
<td>10,000</td>
<td>250,000</td>
</tr>
<tr>
<td>San Diego Gas &amp; Electric Co.</td>
<td>50,000</td>
<td>250,000</td>
</tr>
<tr>
<td>Southern California Edison Co.</td>
<td>50,000</td>
<td>250,000</td>
</tr>
<tr>
<td>U.S. Bureau of Reclamation</td>
<td>40,000</td>
<td>250,000</td>
</tr>
<tr>
<td>United Electric Co.</td>
<td>10,000</td>
<td>250,000</td>
</tr>
</tbody>
</table>

**Total Sales of Electric Energy (15)** | 61,867,176 | $124,254,719

1* *Data from the $1,000,000,000 shown on Table 6 because of technical adjustments.
### TABLE 2

**FEDERAL COLUMBIA RIVER POWER SYSTEM**

General Specifications, Projects Existing, Under Construction and Authorized

June 30, 1969

<table>
<thead>
<tr>
<th>Project Description</th>
<th>Operating Agency</th>
<th>Location</th>
<th>Stream</th>
</tr>
</thead>
<tbody>
<tr>
<td>Columbia</td>
<td>OR</td>
<td>Oregon</td>
<td>Columbia</td>
</tr>
<tr>
<td>Grand Coulee</td>
<td>OR</td>
<td>Oregon</td>
<td>Columbia</td>
</tr>
<tr>
<td>Grand Coulee</td>
<td>WA</td>
<td>Washington</td>
<td>Columbia</td>
</tr>
<tr>
<td>Hungry Horse</td>
<td>OR</td>
<td>Oregon</td>
<td>Snake River</td>
</tr>
<tr>
<td>Dalles</td>
<td>OR</td>
<td>Oregon</td>
<td>North Santiam</td>
</tr>
<tr>
<td>McNary</td>
<td>OR</td>
<td>Oregon</td>
<td>M.F., Williamette</td>
</tr>
<tr>
<td>Beckford</td>
<td>OR</td>
<td>Oregon</td>
<td>North Santiam</td>
</tr>
<tr>
<td>Brier Falls</td>
<td>OR</td>
<td>Oregon</td>
<td>M.F., Williamette</td>
</tr>
<tr>
<td>Ice Harbor</td>
<td>OR</td>
<td>Oregon</td>
<td>South Santiam</td>
</tr>
<tr>
<td>Hells Canyon</td>
<td>OR</td>
<td>Oregon</td>
<td>M.F., Williamette</td>
</tr>
<tr>
<td>Mindiak</td>
<td>OR</td>
<td>Oregon</td>
<td>Snake River</td>
</tr>
<tr>
<td>Box Canyon</td>
<td>OR</td>
<td>Oregon</td>
<td>Snake River</td>
</tr>
<tr>
<td>Black Canyon</td>
<td>OR</td>
<td>Oregon</td>
<td>Payette</td>
</tr>
<tr>
<td>Anderson Ranch</td>
<td>OR</td>
<td>Oregon</td>
<td>S. F., Buse</td>
</tr>
<tr>
<td>Palisades</td>
<td>OR</td>
<td>Oregon</td>
<td>Snake River</td>
</tr>
<tr>
<td>Cooper</td>
<td>OR</td>
<td>Oregon</td>
<td>M.F., Manker</td>
</tr>
<tr>
<td>Gavin Point</td>
<td>OR</td>
<td>Oregon</td>
<td>Middle Santiam</td>
</tr>
<tr>
<td>Hood Canal</td>
<td>OR</td>
<td>Oregon</td>
<td>Snake River</td>
</tr>
<tr>
<td>John Day</td>
<td>OR</td>
<td>Oregon</td>
<td>Columbia</td>
</tr>
<tr>
<td>Lower Monumental</td>
<td>OR</td>
<td>Oregon</td>
<td>Snake River</td>
</tr>
<tr>
<td>Lower Granite</td>
<td>OR</td>
<td>Oregon</td>
<td>Snake River</td>
</tr>
<tr>
<td>Teleset</td>
<td>OR</td>
<td>Oregon</td>
<td>Snake River</td>
</tr>
<tr>
<td>Last Creek</td>
<td>OR</td>
<td>Oregon</td>
<td>Buse</td>
</tr>
<tr>
<td>Damsel</td>
<td>OR</td>
<td>Oregon</td>
<td>M.F., Chinook</td>
</tr>
<tr>
<td>Shirley</td>
<td>OR</td>
<td>Oregon</td>
<td>S. F., Manker</td>
</tr>
<tr>
<td>Healy</td>
<td>OR</td>
<td>Oregon</td>
<td>Mount Hood</td>
</tr>
<tr>
<td>Austin</td>
<td>OR</td>
<td>Oregon</td>
<td>Wash. Ed.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Project Description</th>
<th>Initial Date in Service</th>
<th>Number of Units</th>
<th>Total Capacity Kilowatts</th>
<th>Number of Units</th>
<th>Total Capacity Kilowatts</th>
<th>Number of Units</th>
<th>Total Capacity Kilowatts</th>
<th>Number of Units</th>
<th>Total Capacity Kilowatts</th>
</tr>
</thead>
<tbody>
<tr>
<td>Columbia</td>
<td>June 1934</td>
<td>10</td>
<td>518,400</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Grand Coulee</td>
<td>Sept. 1941</td>
<td>18</td>
<td>2,626,000</td>
<td>6</td>
<td>3,856,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grand Coulee</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hungry Horse</td>
<td>Oct. 1952</td>
<td>4</td>
<td>285,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dalles</td>
<td>July 1953</td>
<td>2</td>
<td>100,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>McNary</td>
<td>Nov. 1953</td>
<td>14</td>
<td>1,590,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beckford</td>
<td>June 1954</td>
<td>1</td>
<td>16,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Brier Falls</td>
<td>Dec. 1954</td>
<td>3</td>
<td>120,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ice Harbor</td>
<td>May 1955</td>
<td>1</td>
<td>11,250</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hells Canyon</td>
<td>May 1962</td>
<td>2</td>
<td>30,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mindiak</td>
<td>May 1949</td>
<td>7</td>
<td>13,600</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Box Canyon</td>
<td>May 1949</td>
<td>3</td>
<td>1,500</td>
<td></td>
<td></td>
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<td></td>
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</tr>
<tr>
<td>Black Canyon</td>
<td>Dec. 1956</td>
<td>2</td>
<td>8,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Anderson Ranch</td>
<td>May 1960</td>
<td>2</td>
<td>27,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Palisades</td>
<td>Feb. 1957</td>
<td>4</td>
<td>114,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cooper</td>
<td>Feb. 1964</td>
<td>2</td>
<td>25,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gavin Point</td>
<td>June 1967</td>
<td>2</td>
<td>100,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hood Canal</td>
<td>Aug. 1968</td>
<td>8</td>
<td>1,080,000</td>
<td>8</td>
<td>1,080,000</td>
<td></td>
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<td></td>
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</tr>
<tr>
<td>Lower Monumental</td>
<td>May 1939</td>
<td>1</td>
<td>130,000</td>
<td>2</td>
<td>270,000</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Lower Granite</td>
<td></td>
<td></td>
<td></td>
<td>3</td>
<td>405,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Teleset</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>16,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Last Creek</td>
<td></td>
<td></td>
<td></td>
<td>2</td>
<td>48,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Damsel</td>
<td></td>
<td></td>
<td></td>
<td>3</td>
<td>402,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shirley</td>
<td></td>
<td></td>
<td></td>
<td>1</td>
<td>4,260</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Healy</td>
<td></td>
<td></td>
<td></td>
<td>4</td>
<td>420,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Austin</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>540,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Total installed capacity:** 6,074,150, 7,665,000, 9,370,000, 5,728,000, 20,971,000

| Total number of projects | 25 | 6 | 2 | 0 | 33 |

---

1. OR - Corps of Engineers, BR - Bureau of Reclamation.
2. Includes three development dams and increase of 17,000 kw each for three proposed projects.
3. Includes an increase of 17,000 kw each for 15 units to be erected and the 600,000 kw units being installed at the Hanford Power Plant.
### TABLE 3

**PACIFIC NORTHWEST GENERATION**

Nameplate Rating in Kilowatts of Plants Existing, Under Construction and Authorized or Licensed

**June 30, 1969**

<table>
<thead>
<tr>
<th>Ownership Plants</th>
<th>Rating Plants</th>
<th>Rating Plants</th>
<th>Rating Plants</th>
<th>Rating Plants</th>
</tr>
</thead>
<tbody>
<tr>
<td>Federal Columbia River Power System</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>26</td>
<td>8,074,150</td>
<td>6</td>
<td>7,985,000</td>
</tr>
<tr>
<td>Privately Owned Agencies</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>43</td>
<td>5,510,461</td>
<td>1</td>
<td>503,600</td>
</tr>
<tr>
<td>Thermal</td>
<td>20</td>
<td>586,651</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total Privately Owned Agencies</td>
<td>63</td>
<td>6,497,112</td>
<td>1</td>
<td>503,600</td>
</tr>
<tr>
<td>Publicly Owned Agencies</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>93</td>
<td>3,932,542</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Thermal</td>
<td>11</td>
<td>251,168</td>
<td>2</td>
<td>2,505,000</td>
</tr>
<tr>
<td>Total Publicly Owned Agencies</td>
<td>104</td>
<td>4,183,710</td>
<td>2</td>
<td>2,505,000</td>
</tr>
<tr>
<td>Pacific Northwest Agencies</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>161</td>
<td>17,517,153</td>
<td>7</td>
<td>8,188,600</td>
</tr>
<tr>
<td>Thermal</td>
<td>31</td>
<td>1,237,819</td>
<td>2</td>
<td>2,505,000</td>
</tr>
<tr>
<td>Total Pacific Northwest Agencies</td>
<td>192</td>
<td>18,754,972</td>
<td>9</td>
<td>10,693,600</td>
</tr>
</tbody>
</table>

1Includes additions to projects existing or under construction.
2Includes projects not presently licensed, but scheduled as part of the Pacific Northwest Hydro-Thermal Power Program.

### TABLE 4

**ELECTRIC ENERGY ACCOUNT FOR BONNEVILLE POWER ADMINISTRATION FISCAL YEAR 1969**

Energy Received (millions of kilowatt-hours)

Energy Generated for BPA
- Bureau of Reclamation: 15,215
- Corps of Engineers: 35,540
- Washington Public Power Supply System: 3,884
- Power interchanged in: 35,726

Total received: 90,365

Energy Delivered (millions of kilowatt-hours)
- Sales: 51,802
- Power interchanged out: 34,857
- Used by the Administration: 51

Total delivered: 86,710

Energy losses in transmission and transformation: 3,665

Total (kilowatt-hours): 90,365

Losses in percent of total received: 4.0%

Maximum demand on Federal plants (kilowatts)
- January 11, 1969, 5–6 p.m. PST: 8,433,000
- Load factor in percent of total generated for BPA: 74.0%

### TABLE 5

**GENERATION BY THE PRINCIPAL ELECTRIC UTILITY SYSTEMS OF THE PACIFIC NORTHWEST**

Fiscal Year 1969

<table>
<thead>
<tr>
<th>Utility</th>
<th>Kilowatt-hours (Billion)</th>
<th>Of Total Generation (Percent)</th>
</tr>
</thead>
</table>

Publicly Owned:
- Federal Columbia River Power System: 54.1 49.8
- Grant County PUD: 10.6 9.7
- Chelan County PUD: 6.5 6.0
- Seattle City Light: 6.2 5.7
- Douglas County PUD: 3.9 3.6
- Tacoma City Light: 2.4 2.2
- Eugene Water & Electric Board: 0.4 0.4
- Pend Oreille County PUD: 0.4 0.4

Total Publicly Owned: 84.5 77.8

Privately Owned:
- Idaho Power Company: 7.6 7.0
- Montana Power Company: 4.6 4.2
- Pacific Power and Light Co.: 4.4 4.1
- Washington Water Power Co.: 3.8 3.5
- Portland General Electric Co.: 2.4 2.2
- Puget Sound Power and Light Co.: 1.3 1.2

Total Privately Owned: 24.1 22.2

Total Generation: 108.6 100.0

1Generation shown is for members of the Northwest Power Pool plus Pend Oreille County PUD and Washington Public Power Supply System, Utah Power & Light Co., British Columbia Hydro and Power Authority and West Kootenay Power & Light, who are members of the Power Pool, are not included because their service area lies outside the Pacific Northwest.
2Includes generation from the Washington Public Power Supply System’s Hanford steam plant (NPR).
### TABLE 6
**FEDERAL COLUMBIA RIVER POWER SYSTEM**
Operating Results on the Repayment Basis
Fiscal Years 1969 and 1968
(In thousands of dollars)

<table>
<thead>
<tr>
<th>REVENUES</th>
<th>F.Y. 1969</th>
<th>F.Y. 1968</th>
<th>Amount</th>
<th>Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bonneville Power Administration</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales of electric energy:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Publicly owned utilities</td>
<td>55,752</td>
<td>49,135</td>
<td>6,617</td>
<td>13.5</td>
</tr>
<tr>
<td>Privately owned utilities</td>
<td>16,967</td>
<td>12,516</td>
<td>4,451</td>
<td>35.6</td>
</tr>
<tr>
<td>Federal agencies</td>
<td>4,662</td>
<td>5,474</td>
<td>(812)</td>
<td>14.8</td>
</tr>
<tr>
<td>Aluminum industry</td>
<td>40,871</td>
<td>34,202</td>
<td>6,669</td>
<td>19.5</td>
</tr>
<tr>
<td>Other industry</td>
<td>5,333</td>
<td>5,296</td>
<td>37</td>
<td>.7</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>123,585</td>
<td>106,623</td>
<td>16,962</td>
<td>15.9</td>
</tr>
<tr>
<td>Other operating revenues:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wheeling revenues</td>
<td>9,160</td>
<td>6,363</td>
<td>2,797</td>
<td>44.0</td>
</tr>
<tr>
<td>Other revenues</td>
<td>1,574</td>
<td>1,689</td>
<td>(115)</td>
<td>(6.8)</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>10,734</td>
<td>8,052</td>
<td>2,682</td>
<td>33.3</td>
</tr>
<tr>
<td><strong>Total Bonneville Power Administration Revenues</strong></td>
<td>134,319</td>
<td>114,675</td>
<td>19,644</td>
<td>17.1</td>
</tr>
<tr>
<td><strong>Associated Projects</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other operating revenues</td>
<td>2,958</td>
<td>3,213</td>
<td>(255)</td>
<td>(7.9)</td>
</tr>
<tr>
<td><strong>Total power system operating revenues</strong></td>
<td>137,277</td>
<td>117,888</td>
<td>19,389</td>
<td>16.4</td>
</tr>
<tr>
<td><strong>EXPENSES</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Purchase and exchange power</td>
<td>12,526</td>
<td>12,755</td>
<td>(229)</td>
<td>(1.8)</td>
</tr>
<tr>
<td>Operating expenses</td>
<td>23,473</td>
<td>20,504</td>
<td>2,969</td>
<td>14.5</td>
</tr>
<tr>
<td>Maintenance and other expenses</td>
<td>10,612</td>
<td>11,075</td>
<td>(463)</td>
<td>(4.2)</td>
</tr>
<tr>
<td><strong>Total power system expenses</strong></td>
<td>46,611</td>
<td>44,334</td>
<td>2,277</td>
<td>5.1</td>
</tr>
<tr>
<td><strong>INTEREST</strong></td>
<td></td>
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<td></td>
<td></td>
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<tr>
<td>Interest on Federal investment</td>
<td>49,005</td>
<td>42,240</td>
<td>6,765</td>
<td>16.0</td>
</tr>
<tr>
<td>Less interest charged to construction</td>
<td>5,681</td>
<td>4,648</td>
<td>1,033</td>
<td>22.2</td>
</tr>
<tr>
<td><strong>Total power system interest</strong></td>
<td>43,324</td>
<td>37,592</td>
<td>5,732</td>
<td>15.2</td>
</tr>
<tr>
<td><strong>Total power system expenses and interest</strong></td>
<td>89,935</td>
<td>81,926</td>
<td>8,009</td>
<td>9.8</td>
</tr>
<tr>
<td><strong>BALANCE AVAILABLE FOR REPAYMENT OF POWER SYSTEM INVESTMENT AND REPLACEMENTS</strong></td>
<td>47,342</td>
<td>35,962</td>
<td>11,380</td>
<td>31.6</td>
</tr>
</tbody>
</table>
## TABLE 7
**FEDERAL COLUMBIA RIVER POWER SYSTEM REPAYMENT STUDY FOR F.Y. 1969**

### AUTHORIZED PROJECTS

<table>
<thead>
<tr>
<th>Year</th>
<th>Amounts in $1,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>1979</td>
<td>580,452</td>
</tr>
<tr>
<td>1980</td>
<td>630,125</td>
</tr>
<tr>
<td>1981</td>
<td>610,906</td>
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<td>610,906</td>
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<td>1983</td>
<td>610,906</td>
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<td>1984</td>
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<tr>
<td>1985</td>
<td>610,906</td>
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<tr>
<td>1986</td>
<td>610,906</td>
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<td>1987</td>
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<td>1988</td>
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<tr>
<td>1989</td>
<td>610,906</td>
</tr>
<tr>
<td>1990</td>
<td>610,906</td>
</tr>
</tbody>
</table>

### NOTE:

This repayment study is similar to those included in the EPA Rose River Project Annual Report for fiscal year 1956. However, several changes in this year's study are of sufficient significance to warrant explanation.

1. The Bureau of Reclamation updated its estimate of the cost to complete reclamation project BPA 509.9 to $40 million. The reclamation project is for the construction of the Sacramento Project. The Bureau of Reclamation increased the total cost of the project from $28 million to $40 million, which total $40 million more than such assistance included in the F.Y. 1969 Annual Report.

2. Previously, the cost of obtaining power through purchase and exchange agreements had been included in operation and maintenance costs, but as of the amount of purchase and exchange power increased to exceed 1977, this study shows it in a separate column.

3. This fiscal year 1969 study ran through the year 1968, as this was the final year for payment of the last installment of the federal reclamation assistance. The total amount provided by the Bureau of Reclamation for the reclamation assistance outside the authorized repayment period for the last install- ments to the year 1973. This estimate is due to the 1978 revision of the reclamation assistance program. The Bureau of Reclamation has estimated the cost of reclamation assistance outside the authorized repayment period for the last install- ments to the year 1973. This estimate is due to the 1978 revision of the reclamation assistance program. The Bureau of Reclamation has estimated the cost of reclamation assistance outside the authorized repayment period for the last install- ments to the year 1973.

4. As a result, 1980 was included at a reasonable termination date. This study shows that all power costs are fully capitalized and that estimates of surpluses were used to carry all remaining power costs.

### TABLE 8

<table>
<thead>
<tr>
<th>Year</th>
<th>Amounts in $1,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>1979</td>
<td>580,452</td>
</tr>
<tr>
<td>1980</td>
<td>630,125</td>
</tr>
<tr>
<td>1981</td>
<td>610,906</td>
</tr>
<tr>
<td>1982</td>
<td>610,906</td>
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<td>1983</td>
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<td>1984</td>
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<td>1985</td>
<td>610,906</td>
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<td>1986</td>
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<td>1987</td>
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<td>1988</td>
<td>610,906</td>
</tr>
<tr>
<td>1989</td>
<td>610,906</td>
</tr>
<tr>
<td>1990</td>
<td>610,906</td>
</tr>
</tbody>
</table>
TABLE 8
BONNEVILLE POWER ADMINISTRATION
REVENUE AND REVENUE TRENDS

Sales of energy, firm and nonfirm
by class of customer and miscellaneous power revenues

(In thousands of dollars)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Aluminum Industry</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Firm</td>
<td>15,293</td>
<td>14,978</td>
<td>14,341</td>
<td>14,382</td>
<td>15,733</td>
<td>16,068</td>
<td>17,299</td>
<td>21,652</td>
<td>27,530</td>
<td>32,186</td>
</tr>
<tr>
<td>Nonfirm</td>
<td>2,168</td>
<td>1,982</td>
<td>3,042</td>
<td>3,715</td>
<td>5,297</td>
<td>6,930</td>
<td>8,994</td>
<td>8,719</td>
<td>6,672</td>
<td>8,715</td>
</tr>
<tr>
<td>Total aluminum</td>
<td>17,461</td>
<td>16,960</td>
<td>17,383</td>
<td>18,097</td>
<td>21,030</td>
<td>25,996</td>
<td>26,293</td>
<td>30,371</td>
<td>34,202</td>
<td>40,871</td>
</tr>
<tr>
<td>Trend percentages</td>
<td>100%</td>
<td>100%</td>
<td>104%</td>
<td>120%</td>
<td>132%</td>
<td>151%</td>
<td>174%</td>
<td>196%</td>
<td>234%</td>
<td>100%</td>
</tr>
<tr>
<td>Other Industry</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nonfirm</td>
<td>868</td>
<td>613</td>
<td>855</td>
<td>625</td>
<td>1,064</td>
<td>1,342</td>
<td>1,569</td>
<td>1,129</td>
<td>962</td>
<td>907</td>
</tr>
<tr>
<td>Total other industry</td>
<td>4,031</td>
<td>3,818</td>
<td>4,049</td>
<td>3,552</td>
<td>4,495</td>
<td>4,950</td>
<td>5,370</td>
<td>4,906</td>
<td>5,296</td>
<td>5,333</td>
</tr>
<tr>
<td>Trend percentages</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>88%</td>
<td>112%</td>
<td>123%</td>
<td>133%</td>
<td>123%</td>
<td>131%</td>
<td>132%</td>
</tr>
<tr>
<td>Publicly Owned Utilities</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Firm</td>
<td>28,304</td>
<td>29,520</td>
<td>32,598</td>
<td>35,466</td>
<td>36,965</td>
<td>41,231</td>
<td>46,643</td>
<td>50,215</td>
<td>41,931</td>
<td>54,719</td>
</tr>
<tr>
<td>Nonfirm</td>
<td>357</td>
<td>583</td>
<td>1,340</td>
<td>682</td>
<td>746</td>
<td>507</td>
<td>1,873</td>
<td>911</td>
<td>7,204</td>
<td>1,033</td>
</tr>
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<td>Total publicly owned utilities</td>
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<td>30,103</td>
<td>33,938</td>
<td>36,148</td>
<td>37,711</td>
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<td>48,516</td>
<td>51,126</td>
<td>49,135</td>
<td>55,752</td>
</tr>
<tr>
<td>Trend percentages</td>
<td>100%</td>
<td>100%</td>
<td>118%</td>
<td>126%</td>
<td>132%</td>
<td>146%</td>
<td>169%</td>
<td>178%</td>
<td>171%</td>
<td>195%</td>
</tr>
<tr>
<td>Privately Owned Utilities</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Firm</td>
<td>9,907</td>
<td>8,338</td>
<td>5,678</td>
<td>6,900</td>
<td>4,974</td>
<td>4,874</td>
<td>7,743</td>
<td>11,062</td>
<td>8,418</td>
<td>13,799</td>
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<tr>
<td>Nonfirm</td>
<td>2,659</td>
<td>1,301</td>
<td>1,536</td>
<td>332</td>
<td>781</td>
<td>663</td>
<td>1,519</td>
<td>1,691</td>
<td>4,098</td>
<td>3,168</td>
</tr>
<tr>
<td>Total privately owned utilities</td>
<td>12,566</td>
<td>9,639</td>
<td>7,214</td>
<td>7,232</td>
<td>5,755</td>
<td>5,537</td>
<td>9,262</td>
<td>12,753</td>
<td>12,516</td>
<td>16,967</td>
</tr>
<tr>
<td>Trend percentages</td>
<td>100%</td>
<td>100%</td>
<td>118%</td>
<td>126%</td>
<td>132%</td>
<td>146%</td>
<td>169%</td>
<td>178%</td>
<td>171%</td>
<td>195%</td>
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<tr>
<td>Federal Agencies</td>
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<td></td>
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<td></td>
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<tr>
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<td>6,217</td>
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<td>7,088</td>
<td>5,874</td>
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<td>3,536</td>
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<td>Nonfirm</td>
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<td>281</td>
<td>253</td>
<td>303</td>
<td>183</td>
<td>872</td>
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<td>342</td>
<td>1,334</td>
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<td>6,475</td>
<td>6,470</td>
<td>6,949</td>
<td>7,271</td>
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<td>5,457</td>
<td>5,541</td>
<td>5,465</td>
<td>4,662</td>
</tr>
<tr>
<td>Trend percentages</td>
<td>100%</td>
<td>104%</td>
<td>104%</td>
<td>112%</td>
<td>117%</td>
<td>108%</td>
<td>89%</td>
<td>85%</td>
<td>88%</td>
<td>75%</td>
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<tr>
<td>Sales of Electric Energy</td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Firm</td>
<td>62,653</td>
<td>62,236</td>
<td>62,028</td>
<td>66,321</td>
<td>68,191</td>
<td>71,655</td>
<td>78,032</td>
<td>91,904</td>
<td>87,345</td>
<td>100,626</td>
</tr>
<tr>
<td>Nonfirm</td>
<td>6,291</td>
<td>4,790</td>
<td>7,028</td>
<td>5,657</td>
<td>8,071</td>
<td>10,314</td>
<td>16,180</td>
<td>12,561</td>
<td>19,278</td>
<td>14,952</td>
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<tr>
<td>Total sales of electric energy</td>
<td>68,944</td>
<td>66,956</td>
<td>69,054</td>
<td>71,078</td>
<td>76,262</td>
<td>81,969</td>
<td>95,012</td>
<td>104,465</td>
<td>106,623</td>
<td>125,585</td>
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<td>Trend percentages</td>
<td>100%</td>
<td>100%</td>
<td>104%</td>
<td>111%</td>
<td>119%</td>
<td>128%</td>
<td>151%</td>
<td>155%</td>
<td>155%</td>
<td>175%</td>
</tr>
<tr>
<td>Miscellaneous Revenues</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wheeling revenues</td>
<td>1,798</td>
<td>2,317</td>
<td>4,019</td>
<td>3,878</td>
<td>4,369</td>
<td>4,397</td>
<td>4,314</td>
<td>4,504</td>
<td>6,363</td>
<td>9,160</td>
</tr>
<tr>
<td>Downstream benefits</td>
<td>1,100</td>
<td>1,460</td>
<td>1,881</td>
<td>1,121</td>
<td>271</td>
<td>103</td>
<td>160</td>
<td>153</td>
<td>153</td>
<td>153</td>
</tr>
<tr>
<td>All other</td>
<td>256</td>
<td>390</td>
<td>310</td>
<td>388</td>
<td>349</td>
<td>807</td>
<td>864</td>
<td>1,082</td>
<td>1,529</td>
<td>1,421</td>
</tr>
<tr>
<td>Total miscellaneous revenues</td>
<td>2,054</td>
<td>2,707</td>
<td>5,420</td>
<td>5,726</td>
<td>6,589</td>
<td>5,316</td>
<td>5,449</td>
<td>5,699</td>
<td>8,052</td>
<td>10,734</td>
</tr>
<tr>
<td>Trend percentages</td>
<td>100%</td>
<td>131%</td>
<td>264%</td>
<td>279%</td>
<td>321%</td>
<td>256%</td>
<td>257%</td>
<td>382%</td>
<td>523%</td>
<td>523%</td>
</tr>
<tr>
<td>Total Revenues</td>
<td>20,088</td>
<td>69,702</td>
<td>74,483</td>
<td>77,704</td>
<td>82,851</td>
<td>87,295</td>
<td>100,461</td>
<td>110,168</td>
<td>114,675</td>
<td>134,219</td>
</tr>
<tr>
<td>Trend percentages</td>
<td>100%</td>
<td>98%</td>
<td>105%</td>
<td>100%</td>
<td>117%</td>
<td>123%</td>
<td>141%</td>
<td>155%</td>
<td>162%</td>
<td>189%</td>
</tr>
</tbody>
</table>

1 F.Y. 1960 base year.
FINANCIAL STATEMENTS
Dear Mr. Secretary:

The General Accounting Office has examined the accompanying financial statements prepared by the Bonneville Power Administration (BPA), Department of the Interior, for the Federal Columbia River Power System for fiscal year 1969.

The designation "Federal Columbia River Power System" is used to describe the integrated Federal power system in the Pacific Northwest comprising the (1) power generating facilities of the Corps of Engineers (Civil Functions), Department of the Army, and of the Bureau of Reclamation, Department of the Interior, and (2) transmission facilities of BPA. BPA markets the power generated by the integrated System. Our examination was made pursuant to the Budget and Accounting Act, 1921 (31 U.S.C. 53), and the Accounting and Auditing Act of 1950 (31 U.S.C. 67).

The statements present the financial results of operations and the source and application of funds in the generating, transmitting, and marketing of electric power for fiscal year 1969 and the financial position of the System at June 30, 1969.

Our examination of the financial statements was made in accordance with generally accepted auditing standards and included tests of the accounting records of the Corps of Engineers, the Bureau of Reclamation, and BPA and such other auditing procedures as we considered necessary in the circumstances. Our preceding examination of financial statements of the System was made for fiscal year 1968.

The accompanying financial statements for the System were prepared on a cost-accounting basis. They do not show the financial results on a repayment basis, either for the fiscal year or cumulatively. (See note 2 to the financial statements.) A separate repayment analysis is prepared by BPA for the System for repayment purposes. Depreciation for cost-accounting purposes is based on an average composite life of 64 years for the entire System whereas a repayment period of 50 years for the generating projects and 45 years for the transmission system is used for repayment purposes. Wholesale power rates are based upon this repayment analysis rather than the cost-based statements.

Our report for fiscal year 1968 stated that the rental costs of space provided by the General Services Administration to BPA were not included in the financial statements for fiscal years 1963 through 1967 but were included for fiscal year 1968. During fiscal year 1969 BPA made a retroactive adjustment, charging $1,162,000 to accumulated net revenues and $1,404,000 to construction, for rental costs for fiscal years 1963 through 1967.

During fiscal year 1969 BPA also treated the cost of the annual System audit, furnished without reimbursement by the General Accounting Office, as an operating cost and made a retroactive adjustment to accumulated net revenues for such costs for fiscal years 1963 through 1968. (See note 7 to the financial statements.) We concur in these adjustments. Also during fiscal year 1969, BPA recorded as assets and as liabilities, for the first time, the costs of "constructively received" material as required by Bureau of the Budget Bulletin 68-10, dated April 26, 1968. This amounted to $9,531,000 at June 30, 1969. (See note 5.e. to the financial statements.)

The accounts and financial statements are subject to retroactive adjustment, because firm allocations of the cost of joint-use facilities to power and other purposes were not made for 5 of the 19 generating projects in service as of June 30, 1969. (See note 3 to the financial statements.) The costs of joint-use facilities of the five projects amounted to about $480 million at June 30, 1969, of which about $337 million was tentatively allocated to power. In prior years, such changes in allocations have sometimes resulted in significant adjustments to (1) the cost of joint-use facilities allocated to power and (2) the reported results of power operations. Note 3 to the financial statements discloses the impact of the changes in the allocations of the five projects for which firm allocations were adopted during fiscal year 1969.

Three of the five projects for which firm allocations had not been made at the end of fiscal year 1959 were placed in service in recent years. The other two proj-
ects—Chief Joseph and Palisades—however, were placed in service in 1955 and 1957, respectively. The Corps of Engineers advised us during our fiscal year 1968 and 1969 audits that it considered the cost allocation for the Chief Joseph project to be firm. The Department of the Interior, however, advised us in connection with our fiscal year 1968 audit that it expected the cost allocation for this project to be firmed up in fiscal year 1969.

The required action was not taken by the Department in fiscal year 1969 to arrive at a firm allocation of costs for the Chief Joseph project. With regard to the Palisades project, the Department informed us that a firm allocation of costs was dependent on the Corps’ approval of the costs allocable to flood control. Because cost allocations are such an important factor in the preparation of the financial statements and repayment analyses for the System, we recommend that appropriate action be taken to see that firm cost allocations are arrived at promptly for these two projects which were placed in service more than 10 years ago.

In addition to the need for firm cost allocations, there are other matters discussed in the notes to the financial statements that remain to be resolved for improved disclosure of the financial position and results of operations of the integrated power system. These other matters include inconsistencies (1) in computing interest expense on the Federal investment and in capitalizing interest costs during construction, (2) in capitalizing preliminary survey and investigation costs, and (3) in reporting accrued annual leave as a liability. The General Accounting Office is currently reviewing these matters with a view toward determining the feasibility of uniform treatment.

As shown in note 4 to the financial statements, interest on the Government’s unrepaid investment, to be repaid from power revenues, is computed at rates ranging from 2-1/2 to 3-1/4 percent. The rates were established for individual projects on the basis of legislative requirements or administrative policies.

On October 27, 1969, the Department of the Interior announced that interest rates on new Federal power projects in fiscal year 1970—for projects where the interest rate is subject to administrative determination—would be increased from 3-1/4 to 4-7/8 percent and that in subsequent years the rate would be based on the average yields on long-term obligations but would be adjusted by not more than one half of 1 percent each July 1. The change, which was announced by the Department in a press release, will result in interest costs more nearly comparable to the Government’s financing costs for new projects. However, a secretarial order directing that the change be made had not been issued at the time our review was completed.

Subject to the financial effects of future adjustments related to adoption of firm cost allocations and of the resolution of other matters described above, the accompanying financial statements, in our opinion, present fairly the assets and liabilities of the Federal Columbia River Power System at June 30, 1969, the financial results of its power operations, and the source and application of its funds for the year then ended, in conformity with accounting principles and standards prescribed for executive agencies of the Federal Government by the Comptroller General of the United States. These accounting principles and standards were applied on a basis consistent with that of the preceding period, except for the cost of “constructively received” materials, rental costs, and the cost of audit services explained above.

Copies of this report are being sent to the Director, Bureau of the Budget; the Administrator, Bonneville Power Administration; the Commissioner of Reclamation; the Secretary of the Army; and the Chief of Engineers.

Sincerely yours,

[Signature]
Comptroller General
of the United States

Enclosures

The Honorable
The Secretary of the Interior
UNITED STATES OF AMERICA
FEDERAL COLUMBIA RIVER POWER SYSTEM
STATEMENT OF COMMERCIAL POWER REVENUES AND EXPENSES
FOR THE FISCAL YEARS ENDED JUNE 30, 1969 AND JUNE 30, 1968
(NOTES 1 AND 2)
(In thousands)

<table>
<thead>
<tr>
<th>Fiscal Year</th>
<th>1969</th>
<th>1968</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPERATING REVENUES:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales of electric energy by Bonneville Power Administration:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Publicly owned utilities</td>
<td>$55,752</td>
<td>$49,135</td>
</tr>
<tr>
<td>Privately owned utilities</td>
<td>16,967</td>
<td>12,516</td>
</tr>
<tr>
<td>Federal agencies</td>
<td>4,662</td>
<td>5,474</td>
</tr>
<tr>
<td>Aluminum industry</td>
<td>40,871</td>
<td>34,202</td>
</tr>
<tr>
<td>Other industry</td>
<td>5,333</td>
<td>5,296</td>
</tr>
<tr>
<td>Total</td>
<td>123,585</td>
<td>106,623</td>
</tr>
<tr>
<td>Other operating revenues:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wheeling revenues</td>
<td>9,160</td>
<td>6,363</td>
</tr>
<tr>
<td>Other revenues</td>
<td>4,532</td>
<td>4,902</td>
</tr>
<tr>
<td>Total</td>
<td>13,692</td>
<td>11,265</td>
</tr>
<tr>
<td>Total operating revenues</td>
<td>137,277</td>
<td>117,888</td>
</tr>
<tr>
<td>OPERATING EXPENSES:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Purchase and exchange power</td>
<td>12,526</td>
<td>12,755</td>
</tr>
<tr>
<td>Operation</td>
<td>23,473</td>
<td>20,504</td>
</tr>
<tr>
<td>Maintenance</td>
<td>11,053</td>
<td>10,796</td>
</tr>
<tr>
<td>Depreciation</td>
<td>19,228</td>
<td>17,116</td>
</tr>
<tr>
<td>Total operating expenses</td>
<td>66,280</td>
<td>61,171</td>
</tr>
<tr>
<td>Net operating revenues</td>
<td>70,997</td>
<td>56,717</td>
</tr>
<tr>
<td>INTEREST AND OTHER DEDUCTIONS (Notes 4 &amp; 5)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest on Federal investment</td>
<td>49,005</td>
<td>42,240</td>
</tr>
<tr>
<td>Interest charged to construction</td>
<td>5,681*</td>
<td>4,648*</td>
</tr>
<tr>
<td>Miscellaneous income deductions, net</td>
<td>441*</td>
<td>279</td>
</tr>
<tr>
<td>Net interest and other deductions</td>
<td>42,883</td>
<td>37,871</td>
</tr>
<tr>
<td>NET REVENUES</td>
<td>$28,114</td>
<td>$18,846</td>
</tr>
<tr>
<td>ACCUMULATED NET REVENUES:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Balance at beginning of year</td>
<td>$296,557</td>
<td>$278,336</td>
</tr>
<tr>
<td>Net revenues — current year</td>
<td>28,114</td>
<td>18,846</td>
</tr>
<tr>
<td>Prior years adjustments (Note 10)</td>
<td>2,087*</td>
<td>625*</td>
</tr>
<tr>
<td>Balance at end of year</td>
<td>$322,584</td>
<td>$296,557</td>
</tr>
</tbody>
</table>

*Denotes deduction

"Notes to the financial statements" are an integral part of this statement.
UNITED STATES OF AMERICA
FEDERAL COLUMBIA RIVER POWER SYSTEM
STATEMENT OF ASSETS AND LIABILITIES
OF THE COMMERCIAL POWER PROGRAM
(NOTES 1 AND 2)
(In thousands)

### ASSETS

<table>
<thead>
<tr>
<th></th>
<th>June 30 1969</th>
<th>June 30 1968</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>FIXED ASSETS:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Completed plant (Schedule A)</td>
<td>$2,362,822</td>
<td>$1,988,280</td>
</tr>
<tr>
<td>Retirement work in progress</td>
<td>11,861</td>
<td>9,380</td>
</tr>
<tr>
<td>Less accumulated depreciation</td>
<td>2,374,683</td>
<td>1,997,660</td>
</tr>
<tr>
<td>Construction work in progress (Schedule A)</td>
<td>217,401</td>
<td>199,562</td>
</tr>
<tr>
<td>Total fixed assets</td>
<td>2,960,472</td>
<td>2,692,982</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>CURRENT ASSETS:</strong></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Unexpended funds</td>
<td>141,784</td>
<td>121,236</td>
</tr>
<tr>
<td>Special funds</td>
<td>3,314</td>
<td>4,101</td>
</tr>
<tr>
<td>Accounts receivable</td>
<td>21,856</td>
<td>17,119</td>
</tr>
<tr>
<td>Materials and supplies</td>
<td>13,942</td>
<td>11,388</td>
</tr>
<tr>
<td>Total current assets</td>
<td>180,896</td>
<td>153,844</td>
</tr>
</tbody>
</table>

| **DEFERRED CHARGE FOR PAYMENT OF IRRIGATION ASSISTANCE (Schedule A) (Note 6)** | 386,943 | 370,544 |

<table>
<thead>
<tr>
<th><strong>OTHER ASSETS AND DEFERRED CHARGES:</strong></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Trust funds</td>
<td>1,092</td>
<td>1,346</td>
</tr>
<tr>
<td>Other assets and deferred charges (Note 5)</td>
<td>13,586</td>
<td>3,078</td>
</tr>
<tr>
<td>Total other assets and deferred charges</td>
<td>14,678</td>
<td>4,424</td>
</tr>
<tr>
<td><strong>TOTAL ASSETS</strong></td>
<td>$3,542,989</td>
<td>$3,221,794</td>
</tr>
</tbody>
</table>

*Denotes deduction

"Notes to the financial statements" are an integral part of this statement.
<table>
<thead>
<tr>
<th></th>
<th>1969</th>
<th>1968</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>LIABILITIES</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>INVESTMENT OF U.S. GOVERNMENT:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Congressional appropriations</td>
<td>$3,587,005</td>
<td>$3,268,890</td>
</tr>
<tr>
<td>Revenues transferred to continuing fund</td>
<td>3,909</td>
<td>3,909</td>
</tr>
<tr>
<td>Transfers from other Federal agencies, net</td>
<td>23,799</td>
<td>22,462</td>
</tr>
<tr>
<td>Interest on Federal investment (Notes 4 and 5)</td>
<td>706,432</td>
<td>639,561</td>
</tr>
<tr>
<td>Gross Federal investment</td>
<td>4,320,145</td>
<td>3,934,822</td>
</tr>
<tr>
<td>Less funds returned to U.S. Treasury</td>
<td>1,567,948</td>
<td>1,437,669</td>
</tr>
<tr>
<td>Net investment of U.S. Government</td>
<td>2,762,197</td>
<td>2,497,153</td>
</tr>
<tr>
<td><strong>ACCUMULATED NET REVENUES:</strong></td>
<td>296,557</td>
<td>278,336</td>
</tr>
<tr>
<td>Balance at beginning of year</td>
<td>28,114</td>
<td>18,846</td>
</tr>
<tr>
<td>Net revenues current year (Exhibit 1)</td>
<td>2,087*</td>
<td>625*</td>
</tr>
<tr>
<td>Prior years adjustments (Note 10)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Balance at end of year</td>
<td>322,584</td>
<td>296,557</td>
</tr>
<tr>
<td><strong>CURRENT LIABILITIES:</strong></td>
<td>61,352</td>
<td>49,428</td>
</tr>
<tr>
<td>Accounts payable</td>
<td>3,937</td>
<td>3,691</td>
</tr>
<tr>
<td>Employees accrued leave (Note 5)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total current liabilities</td>
<td>65,289</td>
<td>53,119</td>
</tr>
<tr>
<td>** LIABILITY OF U.S. GOVERNMENT FOR PAYMENT OF IRRIGATION ASSISTANCE (Schedule A) (Note 6)**</td>
<td>386,943</td>
<td>370,544</td>
</tr>
<tr>
<td><strong>OTHER LIABILITIES AND DEFERRED CREDITS:</strong></td>
<td>1,156</td>
<td>1,346</td>
</tr>
<tr>
<td>Trust fund advances</td>
<td>4,820</td>
<td>3,075</td>
</tr>
<tr>
<td>Other deferred credits</td>
<td>5,976</td>
<td>4,421</td>
</tr>
<tr>
<td>Total other liabilities and deferred credits</td>
<td>$3,542,989</td>
<td>$3,221,794</td>
</tr>
</tbody>
</table>
UNITED STATES OF AMERICA
FEDERAL COLUMBIA RIVER POWER SYSTEM
STATEMENT OF SOURCE AND APPLICATION OF FUNDS
OF COMMERCIAL POWER PROGRAM
FOR FISCAL YEAR ENDING JUNE 30, 1969
(NOTES 1 AND 2)
(In thousands)

**SOURCE OF FUNDS:**

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Congressional appropriations</td>
<td>$318,115</td>
</tr>
<tr>
<td>Transfers from other Federal agencies</td>
<td>1,337</td>
</tr>
<tr>
<td>Gross investment</td>
<td>$319,452</td>
</tr>
<tr>
<td>Revenue from sale of electric energy, including adjustment for prior year of $601</td>
<td>124,186</td>
</tr>
<tr>
<td>Other operating revenue</td>
<td>13,692</td>
</tr>
<tr>
<td><strong>Total revenues</strong></td>
<td>137,878</td>
</tr>
<tr>
<td><strong>Total source of funds</strong></td>
<td>$457,330</td>
</tr>
</tbody>
</table>

**APPLICATION OF FUNDS:**

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation and maintenance expense, purchase and exchange power, miscellaneous income deductions and adjustment for prior years of $601</td>
<td>$47,292</td>
</tr>
<tr>
<td>Investment in electric utility plant (Does not include capitalized interest of $20,707)</td>
<td>266,178</td>
</tr>
<tr>
<td>Return of funds to U.S. Treasury for:</td>
<td></td>
</tr>
<tr>
<td>Operation, maintenance, and miscellaneous expense</td>
<td>$47,292</td>
</tr>
<tr>
<td>Interest on Federal investment, including adjustment for prior years of $1,840</td>
<td>45,164</td>
</tr>
<tr>
<td>Repayment of capital investment</td>
<td>27,823</td>
</tr>
<tr>
<td><strong>Total funds returned to U.S. Treasury</strong></td>
<td>120,279</td>
</tr>
<tr>
<td>Increase in current assets and liabilities, net</td>
<td>14,882</td>
</tr>
<tr>
<td>Increase in other assets and deferred charges, net of other liabilities and deferred credits (excluding irrigation assistance)</td>
<td>8,699</td>
</tr>
<tr>
<td><strong>Total application of funds</strong></td>
<td>$457,330</td>
</tr>
</tbody>
</table>

"Notes to the financial statements" are an integral part of this statement.
### UNITED STATES OF AMERICA

**FEDERAL COLUMBIA RIVER POWER SYSTEM**

**AMOUNT AND ALLOCATION OF PLANT INVESTMENT**

**AS OF JUNE 30, 1969**

**(NOTES 1 AND 3)**

**PROJECTS IN SERVICE AND UNDER CONSTRUCTION**

(In thousands)

<table>
<thead>
<tr>
<th>Project</th>
<th>Commercial Power</th>
<th>Irrigation</th>
<th>Flood Control</th>
<th>Fish and Wildlife</th>
<th>recreation</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>Construction</td>
<td>Work in Progress</td>
<td>Total</td>
<td>Navigation</td>
<td>Control</td>
<td>Fish and Wildlife</td>
</tr>
<tr>
<td></td>
<td>(Notes 3)</td>
<td>(Note 6)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$1,027,560</td>
<td>$866,283</td>
<td>$161,277</td>
<td>$1,027,560</td>
<td>$128,111</td>
<td>176</td>
<td>$540</td>
</tr>
<tr>
<td>379,124</td>
<td>14,667</td>
<td>1,056</td>
<td>379,124</td>
<td>1,034</td>
<td>127</td>
<td>1,034</td>
</tr>
<tr>
<td>29,147</td>
<td>2,695</td>
<td>30,842</td>
<td>29,147</td>
<td>2,911</td>
<td>30,432</td>
<td>84.3</td>
</tr>
<tr>
<td>28,768</td>
<td>2,364</td>
<td>31,132</td>
<td>28,768</td>
<td>2,526</td>
<td>31,294</td>
<td>84.3</td>
</tr>
</tbody>
</table>

**SCHEDULE A**

**COMMERCIAL POWER**

<table>
<thead>
<tr>
<th>Project</th>
<th>Total</th>
<th>Construction</th>
<th>Work in Progress</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>BPA</td>
<td>$1,027,560</td>
<td>$866,283</td>
<td>$161,277</td>
<td>$1,027,560</td>
</tr>
<tr>
<td>CE</td>
<td>$29,147</td>
<td>2,695</td>
<td>30,842</td>
<td>29,147</td>
</tr>
<tr>
<td>BR</td>
<td>$28,768</td>
<td>2,364</td>
<td>31,132</td>
<td>28,768</td>
</tr>
</tbody>
</table>

**IRRIGATION**

<table>
<thead>
<tr>
<th>Returnable from Commercial Power Revenues</th>
<th>NONREIMBURSABLE</th>
<th>Percent of Total Returnable from Commercial Power Revenues</th>
</tr>
</thead>
<tbody>
<tr>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

**RETURNABLE FROM COMMERCIAL POWER REVENUES**

<table>
<thead>
<tr>
<th>Source</th>
<th>Total</th>
<th>Navigation</th>
<th>Flood Control</th>
<th>Fish and Wildlife</th>
<th>Recreation</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

**NOTES**

1. Includes $53,702 construction costs of third power plant.
2. Nonreimbursable road costs.
3. Joint facilities transferred to Bureau of Sports Fisheries and Wildlife. Power portion is included in the Balance Sheet as a deferred item.

"Notes to the financial statements" are an integral part of this statement.
Note 1. Composition of the Federal Columbia River Power System

The Federal Columbia River Power System (FCRPS) is the name applied to the facilities and operations of the Bonneville Power Administration (BPA) and the hydroelectric generating plants constructed and operated by the Corps of Engineers (Corps) or the Bureau of Reclamation (Bureau) for which BPA transmits and markets the power. The projects in service and under construction at June 30, 1969, are listed in Schedule A.

The three agencies are separately managed and financed, and each has its own accounting system. However, the facilities are operated as an integrated power system, and the financial statements for the three agencies are consolidated under the name Federal Columbia River Power System.

Note 2. Basis of Financial Reporting

The accompanying financial statements for the FCRPS are prepared on the cost accounting basis which includes depreciation by the compound interest method as one element of cost. The statements do not show financial results on a repayment basis either for the fiscal year or cumulatively.

The average depreciation life of fixed assets allocated to power is about 85 years for the generating projects and 46 years for the transmission system. The average composite life for the entire system is about 64 years. A separate repayment analysis is prepared for the FCRPS based upon repayment periods of 50 years for the generating projects and 45 years for the transmission system. As a result of the difference between depreciation and repayment periods, depreciation charges accumulated during the repayment periods are much less than repayment requirements for the same periods. Wholesale power rates are based upon the repayment analysis rather than these cost based statements.

Note 3. Cost Allocations

The term "cost allocation" is used to describe the process of assigning the costs of a multipurpose project to the individual purposes it serves. In such a process, joint-use costs of plant and operations are allocated among the purposes served such as power, irrigation, navigation, and flood control. The portion of total project costs allocated to power is included in the FCRPS financial statements.

Cost allocations are designated as tentative or firm. A tentative allocation of costs among purposes may be adjusted retroactively when it is replaced with a firm allocation. A firm allocation may be adjusted, if conditions warrant, but only on a prospective basis.

Firm cost allocations have been adopted for all of the 19 projects in service at June 30, 1969, except the following:

Chief Joseph
Green Peter-Foster
John Day

The Corps considers the cost allocation for the Chief Joseph Project to be a firm allocation because all plant costs are allocated to power except for $176,000 of specific recreation facilities. However, the amount allocated to commercial power is subject to revision because the Department of the Interior has not yet firmed up the suballocation to irrigation pumping power. Therefore, the Department of the Interior considers that the Chief Joseph allocation is tentative.

On July 8, 1968, firm allocations were adopted for Hills Creek, The Dalles, Lookout Point-Dexter, and Cougar Projects. As a result, the allocation of plant investment to power for the four projects increased $6,948,000, and Accumulated Net Revenues decreased $1,157,000.

On June 6, 1969, a firm allocation was adopted for the Detroit-Big Cliff Project, too late to be reflected in year-end accounts. Retroactive adjustments will be made in fiscal year 1970. Plant investment allocated to power will decrease about $1,650,000 (4.0%) and Accumulated Net Revenues at June 30, 1969, will increase about $1,070,000.
Note 4. Interest Rates

An interest rate of 2-1/2% is applied to the unpaid Federal investment for the majority of the projects. The projects which use a rate higher than 2-1/2% are as follows: Bureau projects in service, all using a 3% rate, are: Boise, Columbia Basin, Hungry Horse, Minidoka, Palisades, and Yakima-Roza Division. The Bureau’s Grand Coulee Third Powerplant, which is under construction, carries a 3-1/8% rate.

Corps projects which are under construction and which use rates higher than 2-1/2% are:

- Dworshak: 2-5/8%
- Libby: 3-1/8%
- Lost Creek: 3-1/8%

BPA used the 2-1/2% rate through fiscal year 1963. Subsequently, the following rates were used:

- Fiscal Year 1964: 2-7/8%
- Fiscal Year 1965: 3%
- Fiscal Years 1966 through 1968: 3-1/8%
- Fiscal Year 1969: 3-1/4%

Variations in rates applicable to individual projects are the result of legislative requirements or administrative policies adopted by the various entities.

Note 5. Variations in Practices Among Reporting Entities

The entities of FCRPS each maintain a separate accounting system designed to meet its particular requirements, and variations in reporting practices exist among the entities. However, cooperation among the entities in prior years has led to the adoption of standard practices such as use of the compound interest method of depreciation. The unresolved variations existing during fiscal year 1969 are as follows:

a. The Corps and BPA include interest during construction and other items such as working capital in the base for computation of interest expense. The Bureau does not include in its base interest during construction for four projects and one division of a fifth, and it also excludes other items such as working capital. In addition, the Bureau’s interest base does not include interest from the period of initial allocation to fiscal year 1963 on plant costs of the Columbia Basin Project allocated to future downstream river regulation.

The Bureau excluded these elements based on its interpretation of Federal reclamation law. However, had the Bureau included these elements in its interest base and computed interest at the rate of 2-1/2% for the Columbia Basin and Hungry Horse Projects (the two principal projects involved) accumulated net revenues at June 30, 1969, would have been reduced about $21,600,000.

b. All entities currently capitalize interest during construction. However, the Bureau was not required to include capitalized interest for four projects and one division of a fifth. Had the Bureau capitalized interest during construction at a rate of 2-1/2% for the Columbia Basin and Hungry Horse Projects, plant costs, net of depreciation, would be increased by about $11,700,000 at June 30, 1969. The Bureau computed interest expense at a rate of 3% upon completion of these projects. At that time the Corps and BPA used a 2-1/2% interest rate.

c. The Bureau includes in the costs of its projects, general investigation and development costs which are incurred prior to project authorization. It is the policy of the Corps not to include for FCRPS purposes such costs which are incurred prior to project authorization. The Corps had excluded about $2,100,000 of such costs at June 30, 1969.

d. The accounts of the Corps and BPA properly reflect the liability for accrued but unused annual leave. However, the accounts of the Bureau projects do not include an amount for unused annual leave, estimated to be $666,000 as of June 30, 1969.
As of June 30, 1969, BPA recorded $9,531,000 in Accounts Payable, representing the liability for “constructive receipt” of materials being fabricated for BPA in accordance with its specifications. The offsetting entry was made to Other Assets and Deferred Charges. This entry was made to conform to new Federal concepts for recording such items. A corresponding item for BPA was omitted from the financial statements last year pending full development of the new procedures. The Corps and the Bureau have recorded such liabilities in previous years with offsetting entries principally made to Construction Work in Progress.

**Note 6. Repayment Responsibility for Irrigation Costs**

The revenues of the FCRPS must repay to the United States Treasury the cost of irrigation facilities which benefiting water users in the FCRPS area are unable to repay. At June 30, 1969, this amount was $386,943,000.

Joint project costs of $18,865,000 for the Cougar, Detroit-Big Cliff, Hills Creek, Lookout Point-Dexter, and Green Peter-Foster Projects have been allocated to irrigation pursuant to project authorizations. A determination of water users’ repayment ability will be made at the time the irrigation facilities are proposed for authorization and development. If water users’ repayment ability is insufficient to meet the repayment requirements, irrigation assistance may be required from power revenues, if authorized by Congress. These costs are not included in the accompanying statements because a final determination as to potential repayment from power revenues has not been made.

**Note 7. Costs Incurred by Other Agencies**

The estimated costs of office space provided without charge to BPA by the General Services Administration were not included in the financial statements for the period July 1, 1962, through June 30, 1967. In fiscal year 1969, BPA recorded costs for that period as a charge to Accumulated Net Revenues in the amount of $1,162,000 and $1,404,000 was charged to Construction.

The costs of the annual FCRPS audit, furnished without charge by the General Accounting Office, were not included in the financial statements for the period July 1, 1962, through June 30, 1968. BPA recorded the costs applicable to this period in fiscal year 1969 as a charge to Accumulated Net Revenues in the amount of $336,000. The fiscal year 1969 operating costs include $79,000 for the cost of the audit.

Estimated costs of rental services furnished to the Corps and the Bureau, and other services furnished by other Federal agencies to BPA, the Corps, and the Bureau which are not included in the financial statements are considered to be minor.

**Note 8. Hanford Steam Plant**

BPA, the Washington Public Power Supply System (WPPSS), and 76 utility participants have executed agreements under which BPA receives the electric power generated by the Hanford Steam Plant which was constructed by WPPSS. In return BPA furnishes the participants an amount of power equal in value, at BPA rates, to the annual costs of operating the steam plant and retiring the bonds issued in 1963 to construct the plant. At June 30, 1969, $87,675,000 of the bonds were outstanding and scheduled to be fully retired by 1996. The agreements call for payments to WPPSS by each participant for its portion of the costs of the project based on the Annual Operating Budget. For the year ending June 30, 1969, the participants’ shares of the Annual Operating Budget totaled $7,930,000.

BPA will be required to make the required power deliveries until 1996 even if the Hanford Steam Plant becomes inoperable. However, the Government may acquire ownership of the plant, subject to Congressional approval. Ownership may be acquired after 1996 without cost, with the assumption of all project assets and liabilities. BPA engineers have estimated that by 1996 the plant will have only a net salvage value.
Note 9. Contingent Liabilities

Contingent liabilities applicable to commercial power at June 30, 1969, totaled approximately $17,300,000; $12,200,000 representing claims under the Federal Tort Claims Act (of which $9,700,000 is a claim against the Bonneville Dam by the Yakima Tribe of Indians); and $5,100,000 representing various contractor claims.

Note 10. Adjustments to Accumulated Net Revenues

The following table explains the adjustments which have caused the net decrease in Accumulated Net Revenues of $2,087,000 shown on Exhibits 1 and 2:

<table>
<thead>
<tr>
<th>Description</th>
<th>In Thousands</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Recognition of prior years’ expenses (net) for four Corps projects due to adoption of firm cost allocations in fiscal year 1969</td>
<td>$(1,157)</td>
</tr>
<tr>
<td>2. Recognition of imputed rental costs for fiscal years 1963 through 1967 and costs of the GAO audit for fiscal years 1963 through 1968 not previously reported on FCRPS financial statements</td>
<td>(1,498)</td>
</tr>
<tr>
<td>3. Adjustment for BPA revenues not recorded in prior years</td>
<td>601</td>
</tr>
<tr>
<td>4. Miscellaneous minor adjustments</td>
<td>(33)</td>
</tr>
<tr>
<td>Total</td>
<td>$(2,087)</td>
</tr>
</tbody>
</table>
Grand Coulee with third powerhouse under construction

At Malin—Frank H. Warren, PGE—H. R. Richmond, BPA—Al Ullman, Oregon Congressman—E. Robert de Luccia, PP&L
Celilo Converter Station Switchyard

Don Hodel, right, Deputy Administrator, sworn in by Judge Gus Solomon
APPENDIX

BPA Policy on Commitments

Defined below is the BPA policy on commitments related to power sales to preference customers, electroprocess industries, and private utilities. Policies concerning exchange arrangements with private utilities and sales and exchanges involving areas outside the Pacific Northwest are also stated.

Available Firm Power

The total amount of firm power available for sale or exchange by BPA is derived from assured capability. BPA considers its assured capability as power, after deduction of appropriate forced-outage reserves, from (1) existing Federal projects, (2) Federal projects for which initial construction funds have been appropriated, and (3) contracts such as exchange agreements and net billing arrangements. Under the hydro-thermal program a net billing arrangement is considered an assured resource at the time BPA and the owners contract for the construction of the plant and the purchase of the power.

Preference Customers

BPA will meet on a first-priority basis all the power requirements of preference customers. Such customers will receive at least five years' notice in advance of the time that BPA no longer will have sufficient assured capability to meet all their power requirements and its other firm commitments as defined below.

Electroprocess Industries

The amount of firm power BPA will have available for industry is the balance remaining after subtracting from BPA's assured capability the total of (1) the projected loads of preference customers for a reasonable period in the future, (2) other BPA firm sales or exchange contracts, and (3) reserves for unanticipated load growth.

Reserves for unanticipated load growth under the hydro-thermal program will amount to one-half the annual preference customer and private utility load growth.

The amount of firm power available from BPA to serve new or additional industrial loads will be obtained from new thermal capability over and above that needed together with Federal hydro assured capability to provide for items (1), (2), and (3) immediately above.

Private Utilities

BPA sales of firm hydro power to private utilities will be made after meeting other firm commitments. These sales will terminate in a few years except for the reservation of power for sale in Montana. The amount will be the difference between assured capability and the total of preference customer requirements and other BPA firm sales or exchange contracts. The amount of BPA's sales of peaking capacity, including such sales for forced-outage reserves, will be determined by the balance remaining after subtracting the total of firm loads and reserves for unanticipated load growth from the total of assured capability and the capacity which can be made available by the addition of units at authorized Federal projects. Sales contracts will contain a provision for withdrawal on five years' notice if the power is needed to serve preference customers. Long-term exchange arrangements under which BPA will supply peaking capacity, including use for forced-outage reserves, in exchange for off-peak energy will be made if such capacity can be made available from BPA's assured capability and by the addition of units at authorized Federal projects.

Power Marketed Outside Pacific Northwest

Power is marketed outside the Pacific Northwest in accordance with Public Law No. 88-552. Only energy and peaking capacity surplus to the needs of the Pacific Northwest will be sold outside that region. Under existing contracts energy is withdrawable on not to exceed seven days' notice and peaking capacity is withdrawable on five years' notice* if the power is needed in the Pacific Northwest.

*There are two exceptions to the right to withdraw on five years' notice, both dealing with power exchanges:

(a) Agreements for the use of the direct current line from Celilo to Los Angeles provide for the exchange of 1050 megawatts of peaking capacity from the Pacific Northwest for off-peak energy from California on a 20-year basis with a possible 20-year renewal. During the renewal period the peaking capacity is withdrawable on five years' notice if it is needed in the Pacific Northwest.

(b) Diversity exchanges over the Celilo-Hoover line will be for 20 years and on a firm exchange basis.
BPA ASSOCIATED & MANAGEMENT GROUPS
U.S. DEPARTMENT OF THE INTERIOR
PACIFIC NORTHWEST FIELD COMMITTEE

JOE D. DWYER, Regional Coordinator
Department of the Interior, Portland, Oregon 97208

H. R. RICHMOND, Administrator
Bonneville Power Administration, Portland, Oregon 97208

DONALD R. JOHNSON, Regional Director
Bureau of Commercial Fisheries, Seattle, Washington 98101

DALE M. BALDWIN, Area Director
Bureau of Indian Affairs, Portland, Oregon 97208

EUGENE K. PETERSON, Chief
Division of Basin Studies, PSC
Bureau of Land Management, Portland, Oregon 97208

MARK L. WRIGHT, Chief,
Albany Office of Mineral Resources
Bureau of Mines, Albany, Oregon 97321

FRED J. OVERLY, Regional Director
Bureau of Outdoor Recreation, Seattle, Washington 98104

HAROLD T. NELSON, Regional Director
Bureau of Reclamation, Boise, Idaho 83707

JOHN D. FINDLAY, Regional Director
Bureau of Sport Fisheries and Wildlife, Portland, Oregon 97208

JAMES L. AGEE, Regional Director
Federal Water Pollution Control Admin., Portland, Oregon 97205

WARREN W. HASTINGS, Regional Hydrologist
Geological Survey, Menlo Park, California 94025

JOHN A. RUTTER, District Director
National Park Service, Seattle, Washington 98104
BONNEVILLE REGIONAL ADVISORY COUNCIL

Portland Area

Mr. James C. Howland
General Manager
Cornell, Howland, Hayes & Merryfield
1600 Western Avenue
Corvallis, Oregon 97330

Mr. Alan H. Jones
General Manager
Water and Light Department
City of McMinnville
130 North Baker Street
McMinnville, Oregon 97128

Mr. William C. Klein
Attorney
601 East McLoughlin Boulevard
Vancouver, Washington 98663

Mr. Ivan C. Laird
Vice President and Assistant to the President
Coe-Curry Electric Cooperative, Inc.
Post Office Box 489
Coquille, Oregon 97423

Mr. Donal J. Lane
Executive Secretary
State Water Resources Board
500 Public Service Building
Salem, Oregon 97310

Mr. John Y. Lansing
Regional Vice President, Western Region
General Electric Company
205 Montgomery Street
San Francisco, California 94104

Mr. James J. Leary, Director
Region 21, AFL-CIO
Room 205 Labor Center
201 Southwest Arthur Street
Portland, Oregon 97201

Mr. Herbert Lundy
Editor of the Editorial Page
The Oregonian
1200 S.W. Broadway
Portland, Oregon 97201

Mr. James T. Marr
4000 S.R. Crystal Springs Boulevard
Portland, Oregon 97202

Mr. Eugene E. Marsh
Attorney
525 East Fourth Street
McMinnville, Oregon 97128

Mr. J. M. McClelland, Jr.
Editor and Publisher
Longview Daily News
Longview, Washington 98632

Dr. Charles McKinley
Political Scientist
7001 Southeast 25th Avenue
Portland, Oregon 97202

Mr. Andrew J. Naterlin
Member Oregon State Legislature
623 Southwest Alder Street
Newport, Oregon 97365

Mr. James H. Nichols
Post Office Box 146
Tolovana Park, Oregon 97145

Mr. W. A. Paul
Director of Utilities
State of Oregon
Salem, Oregon 97310

Dr. Wallace A. Pratt
2765 Southeast River Road
Portland, Oregon 97222

Mr. Joe S. Rosenweig
Martin Insurance, Inc.
Post Office Box 759
Longview, Washington 98632

Mr. Lew S. Russell
President
Tidewater Barge Lines, Inc.
6 Beach Drive
Vancouver, Washington 98661

Mr. Kenneth F. Rystrom
Editor of the Editorial Page
The Columbia
701 West 8th Street
Vancouver, Washington 98660

Mr. W. C. Schwenn
Attorney
130 East Lincoln
Hillsboro, Oregon 97123

Mr. Donald J. Sterling, Jr.
Editor of the Editorial Page
Oregon Journal
1230 Southwest Broadway
Portland, Oregon 97201

Mr. Thomas W. Stewart
President
Columbia Power Trades Council
3645 Southeast 32nd Avenue
Portland, Oregon 97232

Mr. Donald H. Tilson
Consultant
Port of Vancouver
8815 Northeast 36th Street
Vancouver, Washington 98662

Mr. Preston B. Varney
Industrial Development Consultant
2530 Ocean Beach
Longview, Washington 98632

Mr. Frank M. Warren
President
Portland General Electric Company
621 S.W. Alder Street
Portland, Oregon 97205

Mr. George W. Watters
Manager
Clark County PUD
Post Office Box 1658
Vancouver, Washington 98683

Mr. Allen P. Wheeler
Master
Oregon State Grange
1313 S.E. 12th Avenue
Portland, Oregon 97214

Mr. Edward Whelan
Executive President
Oregon AFL-CIO
105 High Street, Southeast
Salem, Oregon 97301

Mr. Henry H. Alderman
Secretary
Ruralite Services, Inc.
Post Office Box 1731
Portland, Oregon 97207

Mr. George M. Baldwin
General Manager
The Port of Portland
Post Office Box 5529
Portland, Oregon 97208

Colonel Roy F. Bessey
Water Resources Consultant
600 Southwest Evans Street
Portland, Oregon 97219

Mr. Ivan Bloch
Industrial and Economic Consultant
220 Southwest Portland, Oregon H7204

Mr. A. M. Burdge
Resident Vice President
Nationwide Insurance
601 Southeast Oak Street
Portland, Oregon 97214

Mr. W. E. Campbell
Plant Manager
Reynolds Metals Company
TROUTDALE, Oregon 97060

Mr. Garrett E. Cannon
President
Standard Insurance Company
Post Office Box 711
Portland, Oregon 97207

Dr. David R. Charlton
Chariton Laboratories, Inc.
Post Office Box 1048
Portland, Oregon 97207

Mr. Charles S. Collins
Coordinator
Douglas County Natural Resources
Douglas County Courthouse
Roseburg, Oregon 97470

Mr. Henry G. Curtis
Manager
Northwest Public Power Association
113 West First Street
Vancouver, Washington 98660

Mr. John D. Davis
Dave Foley Insurance, Inc.
Post Office Box 511
Salem, Oregon 97301

Mr. D. G. Hittle
General Manager
Cowlitz County PUD
200 Commerce Street
Longview, Washington 98632

Mr. Charles W. Hodge
Chairman
Pacific Northwest River Basins Commission
Post Office Box 908
Vancouver, Washington 98608

Mr. Kenneth S. Hodge
Industrial Consultant
Clark County Industrial Bureau
424 Columbia Street
Vancouver, Washington 98603

Mr. James H. Howland
General Manager
1600 Western Avenue
Corvallis, Oregon 97330

Mr. Alan J. Jones
General Manager
Water and Light Department
City of McMinnville
130 North Baker Street
McMinnville, Oregon 97128

Mr. William C. Klein
Attorney
601 East McLoughlin Boulevard
Vancouver, Washington 98663

Mr. Ivan C. Laird
Vice President and Assistant to the President
Coe-Curry Electric Cooperative, Inc.
Post Office Box 489
Coquille, Oregon 97423

Mr. Donal J. Lane
Executive Secretary
State Water Resources Board
500 Public Service Building
Salem, Oregon 97310

Mr. John Y. Lansing
Regional Vice President, Western Region
General Electric Company
205 Montgomery Street
San Francisco, California 94104

Mr. James J. Leary, Director
Region 21, AFL-CIO
Room 205 Labor Center
201 Southwest Arthur Street
Portland, Oregon 97201

Mr. Herbert Lundy
Editor of the Editorial Page
The Oregonian
1200 S.W. Broadway
Portland, Oregon 97201

Mr. James T. Marr
4000 S.R. Crystal Springs Boulevard
Portland, Oregon 97202

Mr. Eugene E. Marsh
Attorney
525 East Fourth Street
McMinnville, Oregon 97128

Mr. J. M. McClelland, Jr.
Editor and Publisher
Longview Daily News
Longview, Washington 98632

Dr. Charles McKinley
Political Scientist
7001 Southeast 25th Avenue
Portland, Oregon 97202

Mr. Andrew J. Naterlin
Member Oregon State Legislature
623 Southwest Alder Street
Newport, Oregon 97365

Mr. James H. Nichols
Post Office Box 146
Tolovana Park, Oregon 97145
BONNEVILLE REGIONAL ADVISORY COUNCIL

Seattle Area

Mr. H. Maurice Ahlquist
Director
Washington Department of Water Resources
335 General Administration Building
Olympia, Washington 98501

Mr. Frederick C. Arpke
Economic Consultant
401 Upland Road
Box 184
Medina, Washington 98039

Mr. A. G. Ash
Development Manager
Hooker Industrial Chemicals Division
Post Office Box 164
Tacoma, Washington 98401

Mr. Miner H. Baker
Vice President and Economist
Seattle First National Bank
Post Office Box 3586
Seattle, Washington 98124

Mr. Ken Billington
Executive Director
Washington Public Utility Districts' Association
601 Tower Building
Seattle, Washington 98101

Mr. John D. Bisby
Vice President and Economic Consultant
The Boeing Company
Post Office Box 2707
Seattle, Washington 98124

Mr. George Buck
Owner and Manager
Radio Station KONP
Port Angeles, Washington 98362

Mr. Irving Clark, Jr.
Attorney
334 Fairview Avenue North
Seattle, Washington 98109

Mr. Dan Coughlin
Financial Editor
Seattle Post-Intelligencer
Post Office Box 1900
Seattle, Washington 98111

Mr. Joe Davis
President
Washington State Labor Council
AFL-CIO
2700 First Avenue
Seattle, Washington 98121

Professor Lauren R. Donaldson
College of Fisheries
University of Washington
Seattle, Washington 98105

Mr. P. W. Durnan
Attorney
Post Office Box 651
Lynden, Washington 98264

Mr. C. A. Erdahl
Director of Utilities
City of Tacoma
Post Office Box 11007
Tacoma, Washington 98411

Mr. L. J. Forrest
Vice President
Rayonier, Incorporated
Post Office Box 529
Hoquiam, Washington 98550

Mr. C. Henry Heckendorn
Attorney
1508 Norton Building
801 Second Avenue
Seattle, Washington 98104

Mr. William F. Johnston
Publisher of Student Publications
University of Washington
144 Communications Building
Seattle, Washington 98105

Mr. Vivian B. Jones
Power Management Consultant
3408 North 35th Street
Tacoma, Washington 98407

Mr. Lawrence E. Karrer
Senior Vice President
Puget Sound Power & Light Company
Puget Power Building
Bellevue, Washington 98004

Mr. Henry W. Loren
Member Public Utility Board
Tacoma City Light
Post Office Box 11007
Tacoma, Washington 98411

Mr. Sidney S. McIntyre
President
Skagit Corporation
Post Office Box 151
Sedro-Woolley, Washington 98284

Mr. Robert E. Means
Vice President of Engineering
Pacific Consultants, Inc.
1915 First Avenue
Seattle, Washington 98101

Mr. A. Lars Nelson
Master
Washington State Grange
3104 Western Avenue
Seattle, Washington 98121

Mr. John M. Nelson
Superintendent of Lighting
City of Seattle
1015 Third Avenue
Seattle, Washington 98104

Mr. Francis Pearson
Commissioner
Washington Utilities & Transportation Commission
Insurance Building
Olympia, Washington 98501

Dr. Dix Lee Ray
Director
Pacific Science Center Foundation
200 Second Avenue North
Seattle, Washington 98109

Mr. W. Ronald Richardson
Resident Manager
Crown Zellerbach Corporation
719 White-Henry-Stuart Building
Seattle, Washington 98101

Mr. Dwight R. Scheer
Chief Editorial Writer
The Seattle Times
Fairview Avenue North and John Street
Seattle, Washington 98111

Mr. Sol E. Schultz
Senior Electrical Consultant
Cornell, Howland, Hayes & Merryfield
777-106th Avenue Northeast
Bellevue, Washington 98004

Mr. Edwin W. Taylor
President Board of Commissioners
Mason County PUD No. 3
Route 1, Box 134
Shelton, Washington 98584

Mr. Robert I. Thieme
Vice President and General Manager
Scott Paper Company
West Coast Division
Everett, Washington 98201

Mr. H. S. Thomson
Business Manager
University of Washington
206 Administration Building
Seattle, Washington 98105

Mr. Gerrit Vander Ende
President
Pacific First Federal Savings and Loan Association
11th and Pacific Avenue
Tacoma, Washington 98401

Mr. Harold Walsh
Walsh-Platt Motors
2002 Rucker
Everett, Washington 98201

Mr. Stewart H. White
Electrical Engineer
Weyerhaeuser Company
1015 "A" Street
Tacoma, Washington 98401

Dr. H. F. Yancey
Coal Consultant
16521 Ridgefield Road, N.W.
Seattle, Washington 98177
Mr. A. L. Alford, Jr.
General Manager
Lewiston Tribune
Lewiston, Idaho 83501

Mr. Glenn E. Bandelin
Attorney
Post Office Box 216
Sandpoint, Idaho 83864

Mr. George M. Brunzell
President
The Washington Water Power Company
Post Office Drawer 1445
Spokane, Washington 99210

Mr. Willard Chase
Publisher
Northern Kittitas County Tribune
209 Penn Avenue
Cle Elum, Washington 98922

Mr. Joe Crosswhite
President
Montana State AFL-CIO
Post Office Box 1176
Helena, Montana 59601

Senator Clarence C. Dill
Attorney
763 Lincoln Building
Spokane, Washington 99201

Mr. Howard C. Elmore
Manager
Chelan County FUD
Post Office Box 1231
Wenatchee, Washington 98801

Mr. D. P. Fabrick
Rancher
Choteau, Montana 59422

Mr. John M. George
Director
Clearwater Power Company
Post Office Box 624
Lewiston, Idaho 83501

Mr. Paul Hamilton
Field Secretary
Washington Department of Water Resources
Columbia Basin Office
Post Office Box 146
Ephrata, Washington 98823

Mr. Paul K. Harlow
Rancher
Post Office Box 277
Thompson Falls, Montana 59873

Mr. Leonard F. Jansen
Attorney
North 711 Lincoln Street
Spokane, Washington 99201

Mr. Allen S. Jansen
Dean Emeritus
College of Engineering
University of Idaho
Moscow, Idaho 83843

Mr. Norman L. Krey
Manager Northwest Operations
Kaiser Aluminum & Chemical Corporation
305 Spokane & Eastern Building
Spokane, Washington 99201

Mr. R. E. Mansfield
Attorney
Lane Building
Okanogan, Washington 98840

Mr. Lorin W. Markham
President
National Water Resources Association
South 5524 Garfield
Spokane, Washington 99203

Mr. Carl C. Moore
Manager
Port of Lewiston
513 Main Street
Lewiston, Idaho 83501

Mr. Colin W. Raff
Vice President
The Montana Power Company
Post Office Box 1338
Butte, Montana 59701

Mr. Albert W. Stone
Professor of Law
University of Montana
Missoula, Montana 59801

Mr. John B. Sweat
Bovay Engineers
West 933 Third Avenue
Spokane, Washington 99201

Mr. Nat W. Washington
Member Washington State Legislature
Post Office Box 1204
Ephrata, Washington 98823

Mr. Milo E. Wilson
President
Ravalli County Electric Cooperative
Conner, Montana 59821

Mr. Wilfred R. Woods
Publisher
The Wenatchee Daily World
Post Office Box 1511
Wenatchee, Washington 98801
Mr. Oscar C. Arstein  
Member Idaho State Legislature  
Boise, Idaho 83704

Mr. J. Burns Beal  
Member Idaho Public Utilities Commission  
4820 Cresthaven Drive  
Boise, Idaho 83704

Mr. Bruce Bowler  
Attorney  
244 Sonna Building  
Boise, Idaho 83702

Mr. Lee R. Call  
Publisher  
Star Valley Independent  
Post Office Box 138  
Afton, Wyoming 83110

Mr. Russell G. Cranney  
ChriVer Company  
160 South State Street  
Preston, Idaho 83353

Mr. Darrell H. Dorman  
Retired Labor Official  
3700 Edson Street  
Boise, Idaho 83705

Mr. John V. Evans  
Member Idaho State Legislature  
85 West Depot Street  
Malad City, Idaho 83252

Mr. Cecil Green  
Farmer  
245 North State  
Rigby, Idaho 83442

Dr. Charles H. Kegel  
Academic Vice President  
Idaho State University  
Pocatello, Idaho 83201

Mr. Rod Kvidahl, Resident Manager  
Inorganic Chemicals Division  
FMC Corporation  
Post Office Box 1111  
Pocatello, Idaho 83201

Mr. Robert W. Macfarlane  
President  
Idaho State AFL-CIO  
Post Office Box 269  
Boise, Idaho 83701

Mr. W. Anthony Park  
Attorney  
1385 North Orchard  
Boise, Idaho 83704

Honorable S. E. Pedersen  
Mayor, City of Idaho Falls  
Post Office Box 230  
Idaho Falls, Idaho 83401

Mr. Rogers K. Rose  
President  
Rogers Brothers Company  
Post Office Box 2188  
Idaho Falls, Idaho 83401

Mr. Wallace B. Spencer  
President  
Raft River Rural Electric Cooperative, 7  
Box 817  
Malta, Idaho 83342

Mr. Perry Swisher  
Editor and Publisher  
The Intermountain  
Post Office Box 72  
Pocatello, Idaho 83201
BONNEVILLE REGIONAL ADVISORY COUNCIL
Walla Walla Area

Dr. Fred W. Albaugh
Director
 Battelle Northwest
Post Office Box 997
Richland, Washington 99352

Mr. H. Calvert Anderson
Executive Vice President
Inland Empire Waterways Association
Post Office Box 1098
Walla Walla, Washington 99362

Mr. Thomas C. Bostic
President
Cascade Broadcasting Company
Yakima, Washington 98901

Mr. Byron C. Britton
Editor
The Record Courier
Baker, Oregon 97811

Mr. Martin H. Buchanan
Rancher
Post Office Box 370
Milton-Freewater, Oregon 99352

Mr. Lee E. Darland
Post Office Box 892
Goldendale, Washington 98620

Mr. Benjamin B. Flathers
Rancher
Star Route
Prescott, Washington 98648

Mr. Burton A. Hall
Post Office Box 749
Prosser, Washington 99350

Dr. Charles D. Harrington
President
Douglas United Nuclear, Inc.
300 Federal Building
Richland, Washington 99352

Mr. Eric A. Johnson
729 East Scenic Drive
The Dalles, Oregon 97058

Mr. Glenn C. Lee
Publisher
Tri-City Herald
Post Office Box 9008
Pasco, Washington 99302

Mr. Robert W. Lucas
Executive Editor
Yakima Herald-Republic
114 North Fourth Street
Yakima, Washington 98901

Mr. Charles F. Luce
Chairman of the Board
Consolidated Edison of New York
1 Irving Place
New York, New York 10003

Mr. Mike McCormack
Member Washington State Legislature
1314 Hains
Richland, Washington 99352

Mr. Ernest Mikkelson
President
Board of Trustees
Columbia Rural Electric Association
Waitsburg, Washington 99361

Mr. Ben Musa
Member Oregon State Legislature
Post Office Box 458
The Dalles, Oregon 97058

Mr. Oscar E. Peterson
Box No. 25
Ione, Oregon 97843

Mr. William D. Ray
President
Melcher-Ray Machinery Company
1014 South Ninth Street
Walla Walla, Washington 99362

Mr. S. M. Rhynear
Chief, General Engineering Branch
Atomic Energy Commission
Post Office Box 550
Richland, Washington 99352

Mr. E. O. Thomas
Washington Division Manager
Pacific Power & Light Company
Post Office Box 1346
Yakima, Washington 98901

Mr. Lyle E. Vickers
Member Board of Directors
Horne Electric Cooperative
Buchanan Route
Burns, Oregon 97720

Mr. Glenn C. Walkley
President
Franklin County PUD
Post Office Box 2407
Pasco, Washington 99301

Mr. Robert Welty
Consulting Engineer
Post Office Box 477
The Dalles, Oregon 97058

Mr. R. L. Wooley
Manager
Umatilla Electric
Cooperative Association
Post Office Box 1025
Hermiston, Oregon 97838
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