Susan P. WALKER

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Final Environmental Impact Statement

BONNEVILLE POWER ADMINISTRATION

1979 Wholesale Rate Increase

U.S. Department of Energy

October 1979

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Final Environmental Impact Statement

BONNEVILLE POWER ADMINISTRATION

1979 Wholesale Rate Increase

Responsible Official

Ruth C. Clusen
Assistant Secretary for Environment

U.S. Department of Energy
Washington, D.C. 20545

October 1979

Summary

( ) Draft (X) Final Environmental Statement

Department of Energy, Bonneville Power Administration

1. Type of action: (X) Administrative ( ) Legislative

2. Brief description of action: The action proposed is an increase of approximately 90 percent in Bonneville Power Administration's wholesale power rates to a level sufficient to meet fiscal payout requirements and recover costs. The action also involves a restructuring of existing rate schedules.

3. States involved: California, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming.

4. Summary of environmental impacts and adverse environmental effects: Both physical and socioeconomic impacts would result from implementation of the rate increase and proposed rate schedules. Physical environmental impacts resulting from the rate increase would include a decrease in air pollutant emissions produced by generation of electricity, an increase in urban areas of air pollutant emissions produced by consumption of fuel oil and natural gas, changes in irrigation development, and increased energy conservation. Increased conservation would reduce the amount of new generation required and eliminate associated impacts.

Socioeconomic impacts could be significant for low-income households and energy intensive industries. On an aggregate regional basis, gross output and employment in the Pacific Northwest are expected to decline by less than 1 percent. Minor socioeconomic impacts would be experienced in California.

The time-differentiated features of the rate schedules should produce some effect on household and industrial use of electricity and cause some alteration in residential energy consumption patterns and industrial operating schedules. Also as a result of time-differentiation, reductions in fluctuation of tailwater elevations are expected, benefiting biological productivity in shallow water zones.

The proposed rate for firm capacity sales contains features which should minimize variations in water levels and the likelihood of spill during periods of light load thus benefiting fish and wildlife. The firm capacity rate should also increase the hydro peaking capacity of the Federal System.

5. Alternatives considered: The draft statement explores various rate alternatives including average cost rates, long-run incremental cost rates, time-differentiated average cost rates, various types of share-the-savings rates for non-firm energy sales, baseline rates, conservation rates, industrial rates with availability credits and inclusion of a variable charge in capacity rates.

6. Comments have been requested and received from the following: See Chapter X, Consultation and Coordination

7. Dates filed with the Environmental Protection Agency:

Draft Statement: August 23, 1978

Final Statement:

For additional information contact:
John Kiley, Environmental Manager
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208
Area Code (503) 234-3361, Ext. 5137

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List of Preparers
of the Environmental Impact Statement

Project Director

Edward W. Sienkiewicz
Chief, Branch of Rates
Educational background: BA - 1963 - Mathematics; BA - 1964 - Economics; MA - 1968 - Economics
Experience: Research assistant, University of Oregon (1964-68); instructor in economics (part-time), Portland State University (1968-75); economist, BPA Planning Office (1968-74); Head, Rate Section, BPA (1974-79); Chief, Branch of Rates, BPA (1979-present).

Major Authors

Berlin, John G.
Public Utilities Specialist - BPA Conservation Section
Educational background: BA - 1973 - Economics; MA - 1975 - Economics
Experience: Staff economist with NETL, Inc. and lead consultant on Seattle City Light's 1990 Project (1975-76); industry economist with BPA Rates Section (1976-78); Public Utilities Specialist, Energy Conservation Section, BPA (1978-present).

Esvelt, Terence G.
Industry Economist - BPA Power Requirements Section
Educational background: BA - 1972 - Economics; MA - 1974 - Economics
Experience: Involvement in a variety of environmental projects with BPA (1974-78); load forecasting with BPA Requirements Section (1978-present).

Palmer, Helen W.
Industry Economist - BPA Wholesale Rates Section
Educational background: BS - 1976 - Economics
Experience: Industry economist, BPA rates staff (1976-present).

Taves, John M.
Sociologist - BPA Wholesale Rates Section
Educational background: BA - 1968 - Psychology; MA - 1971 - Social Psychology; PhD - 1975 - Sociology
Experience: Research assistant, Washington State University (1972-73); teaching assistant, Washington State Unversity (1974); assistant professor (sociology), University of Texas at Arlington (1974-1976); work on environmental projects with BPA (1976-present).

Other Contributors

Beebe, William D.
Industry Economist - BPA Transmission and Retail Rates Section
Educational background: BS - 1969 - Economics; MS - 1971 - Economics/History; PhD candidate - Economics/History

Experience: Economic Development Intern Oregon Executive Department (1970); Research assistant, Southern Illinois University (SIU) (1970-72); Teaching assistant - SIU - (1972-74); Business/Economic Instructor, John A. Logan College (1974-75); Business/Economic/History Lecturer, University of Maryland (1975-77); Research Consultant, Oregon Workers Compensation Department (1977-78); BPA Industry Economist (1978-present).

Buckingham, Richard A.
Electrical Engineer - BPA Transmission and Retail Rates Section
Educational background: BS - 1977 - Electrical Engineering and Computer Science
Experience: BPA training assignments with Branch of Substation Design and BPA's Seattle Area Office (1976-77); BPA rates staff (1977-present).

Filip, Patricia A.
Writer - BPA Wholesale Rates Section
Educational background: BA - 1971 - English; MA - 1972 - Journalism
Experience: Work with BPA on environmental review documents (1978-present); writing and editing experience with newspapers and private industry.

Fuqua, Gary L.
Industry Economist - Head, BPA Wholesale Rates Section
Educational background: BS - 1962 - Economics; MS - 1968 - Economics
Experience: Industry economist, State of Oregon (1964-66); financial economist, Federal Home Loan Bank Board (1966-68); economist, U.S. Army Corps of Engineers (1968-75); industry economist, BPA (1975-present).

Hansen, Douglas A.
Assistant Administrative Manager - BPA Division of Management Services
Educational backgound: BA - 1956 - Political Science; MA - 1958 - Public Administration
Experience: Twenty-one years with BPA in various administrative and financial management functions, including development and implementation of the repayment policy for determining revenue requirements and cost-of-service analyses.

Hoffard, Donald G.
Industry Economist - BPA Requirements Section
Educational background: BA - 1965 - Economics; MA - 1968 - Mathematics
Experience: Industry economist with BPA (1968-present); instructor in statistics (part-time), Portland State University (1970-71); instructor in statistics (part-time), Lewis and Clark College (1974-75); worked on Northwest Energy Policy Project (1975-78).

Kler, Albert H.
Public Utilities Specialist - BPA Transmission and Retail Rates Section
Educational backgound: BA - 1947 - Business Administration
Experience: Economist with BPA rate staff (1950-present).

Melton, Shirley R.
Public Utilities Specialist - BPA Wholesale Rates Section
Educational background: BS - 1967 - Mathematics
Experience: As a mathematician was involved in the design and development of computer applications for BPA's Dittmer Control Center power scheduling and dispatching functions (1968-76); Public Utilities Specialist, BPA rates staff (1977-present).

Meyer, Charles E.
Industry Economist - BPA Wholesale Rates Section
Educational background: BA - 1973 - Economics; MA - 1974 - Economics
Experience: Research assistant, Kent State University (1973-74); teaching assistant, Washington State University (1975-76); industry economist with BPA rates staff (1976-present).

Palensky, John R.
Environmental Coordinator - BPA Division of Power Management
Educational background: BS - 1967 - Wildlife Technology (Aquatic Option); MS - 1973 - Fisheries
Experience: Assistant in Fisheries, Oregon State University (1969-73); fishery biologist, Federal Power Commission (1973-76); fishery biologist, BPA (1976-77); environmental specialist, BPA (1977-present).

Pyrch, John B.
Environmental Specialist - BPA Division of Power Management
Educational background: BS - 1968 - Geography; MS - 1973 - Geography
Experience: Involvement in natural resource assessments as part of a regional planning effort in Mindanao, Philippines (1974-75); work on environmental projects with BPA (1975-present).

Seiffert, Randy D.
Environmental Specialist - BPA Thermal Power Section
Educational background: BS - 1971 - Chemical Engineering
Experience: Air quality analysis with Environmental Protection Agency Office of Air Quality Planning and Standards (1972-76); work on environmental projects with BPA (1976-present).

White, Paul L.
Electrical Engineer - BPA Transmission and Retail Rates Section
Educational background: BA - 1951 - Electrical Engineering
Experience: Electrical engineer with Sacramento Municipal Utility District (1951-63); electrical engineer with BPA (1963-present); licensed professional engineer in the States of California and Oregon.

Wilkins, John R.
Regional Economist - BPA Power Requirements Section
Educational background: BS - 1962 - Agricultural Economics; MS - 1968 - Agricultural Economics; PhD - 1979 - Resource Geography
Experience: Over 10 years of experience developing and applying techniques for estimating the economic effects of alternative plans to develop land and water resources, including recent experience estimating the economic effects of electric power policy and resource changes.

1979 WHOLESALE RATE INCREASE
ENVIRONMENTAL STATEMENT

EXECUTIVE SUMMARY

INTRODUCTION

A 90% revenue increase is needed.

The Bonneville Power Administration (BPA) has determined the need for a revenue increase of approximately 90 percent to enable it to meet its financial obligations. Inflation and expansion of regional dependence on increasingly expensive thermal generation are primary reasons underlying the need for this increase. Following completion of various cost and rate studies, BPA developed proposed rate schedules to generate the required revenue. The initial proposed schedules, rate studies, and a draft environmental impact statement were issued in August 1978 and were subject to public review in the fall of 1978. Following the review period, cost studies were updated and the proposed rates were modified as appropriate. A revised rate proposal was issued in July 1979. The revised proposal was also reviewed by the public. Modifications were made and cost data updated prior to the development of the final proposal. The proposed rates are scheduled to become effective on December 20, 1979.

Public involvement was enlisted in developing new rates.

The EIS addresses impacts of BPA's proposal and alternatives.

This environmental impact statement addresses the impacts on both the physical and socioeconomic environment of BPA's rate proposal and alternatives to the proposal. Methods for mitigating the effects of the proposal are also discussed.

LEGAL BASIS FOR BPA's RATE MAKING PROCESS

Rates were designed to comply with legal mandates.

Bonneville's rates were designed in accordance with legal mandates which govern the rate review process and BPA's responsibilities. These mandates stipulate that BPA periodically review its rates, set rates at a level enabling it to continue on a self-financing basis, satisfy its repayment responsibilities, and design rates which are equitable, while promoting widespread, diversified use of electric energy.

REVENUE ALTERNATIVES

Six basic revenue alternatives are explored in the EIS. Although at present BPA cannot legally adopt some of the alternative revenue levels examined, it is possible that BPA's legal responsibilities could change causing

Six revenue alternatives were examined.

some of the alternatives to become viable. The six alternatives include a no action alternative, a revenue level without BPA financing for thermal plants under construction, a reduced revenue level, the proposed revenue level, an increased revenue level, and a revenue level produced by long-run incremental cost (LRIC) or marginal cost pricing.

Under the no action alternative, BPA would maintain its existing revenue level. Bonneville would not be able to meet its repayment obligations under this alternative.

Bonneville did attempt to adopt an alternative which would have allowed the Washington Public Power Supply System (WPPSS) to finance the debt service that BPA is currently obligated to pay on two nuclear plants under construction until they begin commercial operation. This would have enabled BPA to reduce the revenue increase it needed from approximately 90 percent to approximately 30 percent. This alternative was not proposed; however, because when BPA submitted the proposal to the participants in the WPPSS net-billed projects for their required unanimous approval, two utilities did not grant approval.

The reduced revenue level alternative involves modification of Bonneville's repayment criteria, through elimination of the requirement to pay irrigation costs and through amortization of Federal generation facilities over an 85-year period instead of a 50-year period. Congressional approval would be needed to make these changes.

The proposed revenue level was determined as a result of a repayment study conducted by BPA. The study indicated that a revenue increase of approximately 90 percent is necessary for BPA to meet its payout obligations under current repayment policy.

The increased revenue level and LRIC alternatives would require changes in Bonneville's legislative authority.

The magnitude of the rate increase needed to produce the revenue required under marginal cost pricing, plus the fact that this revenue level is not sanctioned by current law, were reasons why this alternative is not being proposed.

IMPACTS OF REVENUE ALTERNATIVES ON REGIONAL POWER CONSUMPTION

Increased revenue levels would result in decreased electrical power consumption.

An econometric simulation model was devised to determine the effect of each revenue alternative on regional power consumption. The model indicated that under Bonneville's proposed 90 percent revenue level, electricity consumption in 1997 is expected to be 3,928 million kWh less than under the no increase scenario, assuming that all other prices are held constant. Fuel oil consumption would be 31,722 million gallons higher and natural gas use would be 18,110 million therms higher than under the base (no increase) case. Use of other electric energy substitutes such as solar energy and cogeneration would be affected only slightly. The marginal cost case would have the greatest effect on Pacific Northwest energy consumption.

Regional industrial growth and employment would be affected only slightly.

An increase in electricity rates should have only a slight influence on the rate of regional industrial growth and even under "worst case" assumptions, the region's employment would be reduced by less than 1 percent with higher energy prices which would result from the proposal.

Load forecasts and generation requirements may be impacted.

Load forecasts may be affected by changes in electricity price as consumers respond by changing their demand for electricity. However, the load forecasts compiled by the region's utilities already incorporate the 1979 Bonneville Power Administration's rate increase of approximately 90 percent.

The proposed 90 percent revenue increase would produce a generation requirement 225 to 675 megawatts (MW) lower than under the no increase scenario. The marginal cost option would result in an even greater reduction in the generation capacity needed.

Physical-environmental impacts would result.

Different revenue levels produce differing impacts on consumption and amount of generation needed to meet demand. Because the particular mix of generation resources needed to meet demand under various alternative revenue levels cannot be accurately predicted, it is difficult to determine the impacts on physical environment associated with each of the alternative revenue requirements. Application of environmental impact coefficients based on 1985 generation mix to different revenue alternatives provides a crude measure of impacts. The 90 percent revenue increase would result in approximately two percent lower environmental residuals in

1997 due to generation than if there were no revenue increase. Unconstrained marginal cost pricing would produce approximately 14 percent less emissions and other impacts from the generation of electricity than would be the case without a rate increase. Human health impacts in urban areas might be impacted slightly as a result of fuel substitutions.

Water use by irrigators would tend to decrease as Bonneville's revenue level increased. Reduction in agricultural water use would allow more energy production at existing hydroelectric dams. Impacts from changes in irrigation development would affect land use patterns, dust levels, and water quality as a result of irrigation runoff. On a regional basis, such changes are expected to be minor.

IMPACTS OF REVENUE ALTERNATIVES ON UTILITIES AND ULTIMATE CONSUMERS

Utilities would be affected by a BPA rate increase to varying degrees.

The impacts of alternate revenue levels on utilities and ultimate consumers were also analyzed. The magnitude of the impact of a Bonneville wholesale revenue increase on utilities would depend on the proportion of the utility's total costs devoted to purchases of Bonneville power. The average wholesale firm power rates to each preference customer under both the existing rate structure and the 90 percent revenue increase alternative are shown in Table V-1 (see Chapter V of the text). The average millage increase in wholesale power rates which would result for each preference utility under each revenue alternative is included in Table V-2. The percentage of each utility's total costs devoted to the purchase of Bonneville power in 1977 is illustrated in Table V-3.

The primary impact in California would be socioeconomic.

Bonneville examined impacts in California from an increase in nonfirm energy rates of the size under consideration and it concluded that the primary impact would be socioeconomic. Higher electricity prices would be expected to change the demand for power in California. Effect on employment would be negligible.

The impact of an increase in revenue level and hence an increase in electrical rates on the households, commercial establishments, irrigators, and industries purchasing power from Bonneville preference customers would be indirect. It is uncertain what these impacts on end users would be because it is unknown how Bonneville's utility customers would pass through a rate increase in their rate structures.

Impacts on low-income consumers could be significant

Effects of an increase in electrical rates on households would vary depending on the amount of income devoted to energy purchases by the household. Household expenditures for electricity are influenced by family size, income level, type of heating, and size, location and type of dwelling. Low-income consumers devote a significantly larger share of their before-tax income to energy than the rest of the population and therefore would be more severely impacted by an increase in electricity rates than higher income consumers.

Industries would be impacted according to intensity of electricity use.

Particular industries would be affected by an increase in power rates according to intensity of their electricity use. The relative importance of electricity to total production costs varies widely from one type of industry to another. Primary metals is the most electrically-intensive industry, followed by mining, chemicals, and pulp and paper. In all the other industrial sectors, electricity purchases account for a small percentage of total costs and therefore impacts of an increase in electrical rates would not be significant. It has been estimated that business and industry could be expected to reduce their electricity use from about 0.1 to 0.3 percent in the short run and from 0.3 to 1.8 percent on the long run for each 1 percent increase in the real price of electricity.

Irrigators would be sensitive to an electricity price increase.

Electricity used for irrigation can be quite sensitive to the price of electricity. A study of the effects of an increase in electricity prices on Pacific Northwest irrigators revealed that in the short run, potential adjustments would be made in water application, pump efficiencies, and amounts of acreage devoted to specific crops. In the long run, potential adjustments would also include new technology, changed irrigation systems, and reduction of irrigated acreage. In the short run, a retail electric rate increase to irrigators of 50 percent (wholesale power costs would rise by somewhat less than 100 percent as a result of BPA's proposed rate increase, and wholesale costs generally represent approximately half of retail costs) would not cause any irrigated acreage to be taken out of production. Farmer's incomes, however, would be reduced because they would not be able to increase the price they receive for their products to offset their increased cost of power. Some marginal farmers would find it uneconomical to continue their operations and would sell their property to farmers who could farm more efficiently.

Indications are that BPA direct-service industries would not change their operations in response to a BPA rate increase, unless BPA were to charge marginal cost rates.

RATE DESIGN ALTERNATIVES AND IMPACTS

Rate design alternatives were considered.

In developing proposed rates to recover needed revenues, BPA considered a variety of rate design alternatives. Bonneville also conducted a number of cost and rate studies, including a fully allocated cost-of-service study, a long run incremental cost-of-service study, and a time-differentiated pricing analysis.

Proposed energy and capacity rates are based on BPA's average cost-of-service study and long-run incremental cost study.

Bonneville developed proposed rates for energy and capacity which are based on BPA's cost-of-service analysis, but then modified somewhat to reflect the results of BPA's long run incremental cost study. Under the proposed rates, the emphasis of the revenue burden is shifted from the capacity rate to the energy rate. Bonneville also considered apportioning costs to energy and capacity strictly on the basis of the cost-of-service study, but decided that an average cost rate design would not provide consumers with a proper price signal and would encourage energy growth. Unadjusted long run incremental cost prices would provide proper price signals, but would produce revenues in excess of BPA's revenue requirement. The method chosen by BPA results in capacity and energy rates which reflect the results of the LRIC study which show energy costs increasing more rapidly than capacity costs. Customers with higher than average load factors would benefit more from rates based strictly on average costs than from the proposed rates. Low load factor customers would experience a lower average cost per kilowatthour of power under the proposed rates than under strict average cost pricing.

Proposed rates are time differentiated.

Bonneville also considered the concepts of time differentiation in the process of designing its rates. Bonneville's proposed rates were developed to reflect the fact that the cost of providing power varies during different time periods and different seasons. Bonneville's proposed firm power energy and capacity rates are seasonally differentiated and the firm power capacity rate is differentiated according to the time of day and season of the year during which capacity is taken. The proposed summer energy season consists of the period from April 1 through August 31, whereas the summer season capacity period is from June 1 through November

31. The on-peak hours for the proposed capacity rate are 7 a.m. to 10 p.m., Monday through Saturday.

Irrigators could profit from a seasonal energy differential.

It is unlikely that the seasonal rate differential would produce a significant change in the annual load factor experienced in the West Group Area. Customers most likely to profit from a seasonal energy differential would probably be those with significant irrigation loads, since the bulk of irrigation power requirements occur during the summer. Winter peaking utilities which serve large numbers of space heating customers would experience higher power costs under the proposed seasonally differentiated rates than under rates which are not seasonally differentiated.

Time-of-day rates could improve daily load factor and trim peak load.

It is very difficult to quantitatively predict the potential impact of time-of-day rates, but experiences elsewhere have indicated that improvements in daily load factor can be expected. Bonneville estimates that through the use of time-of-day rates it would be possible for the January 1989 peak load to be reduced from 33,500 MW to 30,500 MW. The most significant effect would be on the hydrosystem, which would experience a large decrease in fluctuations. Effects of this improved load factor would diminish with time as the composition of future Pacific Northwest load growth changes.

Time-of-day rates would most adversely affect those persons unable to avoid electrical use during peak hours. Lower income consumers could have greater difficulty adjusting to time-of-day rates than higher income consumers because space heating and air conditioning represent a larger proportion of their budgets. In addition, low income customers have smaller and less flexible appliance inventories.

Industries could respond to time-of-day rates.

That certain industries can respond to time-of-day rates by shifting peak loads to off-peak periods is clear, but the magnitude of such potential depends on many variables. Time-of-day rates could also encourage commercial and industrial consumers to alter their operating schedules, creating or expanding use of "graveyard" shifts. Some types of industries would be more able to adjust their schedules than others. Night-time shifts could exert adverse impacts on the physical, mental, and social well being of the workers themselves. Bonneville direct-service industrial customers are not expected to respond to time-of-day rates since they operate 24 hours a day all year at extremely high load factors.

Time-of-day rates could result in significant environmental impacts.

A time-of-day pricing structure could result in significant environmental impacts. With this type of pricing, significant reductions in the fluctuation of water outflow and tailwater elevation are probable. These reductions in fluctuations would be beneficial to biological productivity in the shallow water zone along the edges of rivers and in spawning areas.

Availability credits were considered.

In developing new rates, BPA also explored the issue of availability credits and whether or not the restriction rights it exercises over power sold to direct-service industrial customers should be reflected in lower rates to these customers. BPA analyzed several alternatives before proposing availability credits which would total approximately $32 million in 1980.

A share-the-savings rate is proposed.

Another rate design concept examined by BPA was a share-the-savings rate, or a rate enabling savings realized by utilities in purchasing BPA nonfirm energy to be shared with utilities which purchase power from BPA on a firm basis. Share-the-savings rate design involves a rate established between BPA's cost of providing power and the value of the power to the purchasing utility. The value of the power is based on cost of the resource being displaced by the purchasing utility. Bonneville has proposed a nonfirm energy rate which is flexible and varies depending on negotiations between BPA and the purchasing utility. In no cases would the rate be greater than 20 mills or less than 4.5 mills per kilowatthour during offpeak periods and 6.5 mills per kilowatthour during peak periods. The rates for annual capacity and seasonal capacity also contain features which reflect the share-the-savings concept. Revenues derived from secondary energy sales and excess revenues from firm capacity sales would be applied by BPA to firm power capacity costs, resulting in reduced firm power rates.

It is expected that the proposed share-the-savings rate would, on the average, represent an increase for Southwest utilities over the existing rate the utilities pay for BPA nonfirm power. However, the increase should not affect the amount of secondary energy purchased from BPA because the rate would continue to be much lower than the alternative cost of energy to the purchasing utility. The impact on retail power rates would be small in most cases, but would depend on the portion of a utility's total energy requirements purchased under the rate.

Other rate design issues were explored.

In the proposed rates, BPA eliminated a specific charge for providing delivery point transformation that was initiated in 1974. Bonneville also continued in modified form an at-site discount for capacity purchased for use within 15 miles of a powerplant.

Bonneville studied the feasibility of implementing a two-tier baseline rate which would establish separate rates for thermally versus hydroelectrically generated power. However, BPA's General Counsel indicated that BPA currently lacks authority to implement this type of rate design.

Bonneville explored, but rejected, the option of implementing a special rate for irrigators. Bonneville also studied the issue of rate incentives for conservation and rate forms which would induce conservation.

MITIGATING MEASURES

Impacts on residential consumers could be mitigated by income assistance programs, by conservation, by special rate adjustments, and by forewarning consumers of the rate increase.

The most adverse impact of BPA's proposed rate increase would be its effect on family budgets. This impact could be partially mitigated by existing income support programs including the Federal Food Stamp Program, Federal Aid to Families with Dependent Children, and Supplemental Security Income programs. Increases in basic living costs (including residential electricity costs) result in increases in the benefits provided by these programs. Other potential means of mitigation include fuel stamps, lifeline rates, emergency loans, tax refunds, and governmental subsidies. In addition to direct financial approaches, mitigation could be achieved by assisting consumers in reducing the amount of energy consumed. Consumer education, stricter building and appliance efficiency standards, and insulation retrofit programs could help minimize consumption. While a gradual increase in rates could ease the initial impact of higher rates, the primary value might be more psychological than financial in the long run. Special rate adjustments could be made to ease the impact on customers expected to be most severely impacted by the rate increase. Finally, forewarning consumers regarding the probability of increasing costs of future energy could assist them in anticipating the importance to be attributed to energy efficiency when considering home or appliance purchases. The same would be true for commercial and industrial customers.

Impacts on air quality could also be mitigated.

Impacts on air quality caused by substitution of other fuels for electricity could be mitigated by promoting conservation measures and on-site alternative non-polluting energy systems.

Chapter I
Introduction

A. Bonneville's Role. The Bonneville Power Administration (BPA) is the wholesale marketing agency for electric power generated at the Federal hydroelectric dams in the Columbia River Basin. These dams, built and operated by the Bureau of Reclamation and the Army Corps of Engineers, together with BPA's transmission system, comprise the Federal Columbia River Power System (hereinafter FCRPS) which supplies about 50 percent of the electric energy consumed in the Pacific Northwest and accounts for about 80 percent of the region's high-voltage transmission capacity. By purchase and exchange, BPA also acquires power generated by non-Federal utilities. Bonneville sells power to 149 customers including publicly owned utilities, privately owned utilities, State (California) and Federal agencies, electroprocess industries, and other industries located throughout the Northwest (see Figure I-1). Many of BPA's utility customers have generation of their own in addition to that power obtained from BPA. Except for small amounts from a project (Packwood) jointly owned by several utilities and from the Columbia Storage Power Exchange Agreement, Bonneville is the sole source of supply for 93 of its nongenerating utility customers. Between 70 and 80 percent of BPA sales of firm power 1/ are to public and private electric utilities for resale to ultimate consumers. Bonneville also sells industrial firm power (power over which BPA has special restriction rights) directly to several industries, primarily electroprocess industries. In addition, BPA sells secondary energy, subject to availability, to utilities.

B. Purpose of the Environmental Impact Statement. In the fall of 1979 the Bonneville Power Administration will file new power rate schedules through the Assistant Secretary for Resource Applications with the Federal Energy Regulatory Commission (FERC), an independent regulatory commission within the U.S. Department of Energy (DOE). When cleared by Resource Applications, the new rates will become effective on an interim basis on December 20, 1979, until such time as final confirmation and approval of the proposed rates are rendered by FERC. Bonneville's studies indicate that a revenue increase of approximately 90 percent is necessary to enable BPA to meet its financial obligations. Inflation and expansion of the region's dependence on increasingly expensive thermal generation (see Figure I-2) are primary reasons underlying the need for this increase. Substantial increases in BPA's wholesale power

1/ Stated simply, firm power is power which BPA guarantees to deliver. More exactly, it is firm capacity which is the capacity of the Federal power system to meet peak demand which BPA assures will be available except when prevented by uncontrollable forces, together with the associated firm energy which is energy which BPA assures its customers will be available over a given time except when prevented by uncontrollable forces.

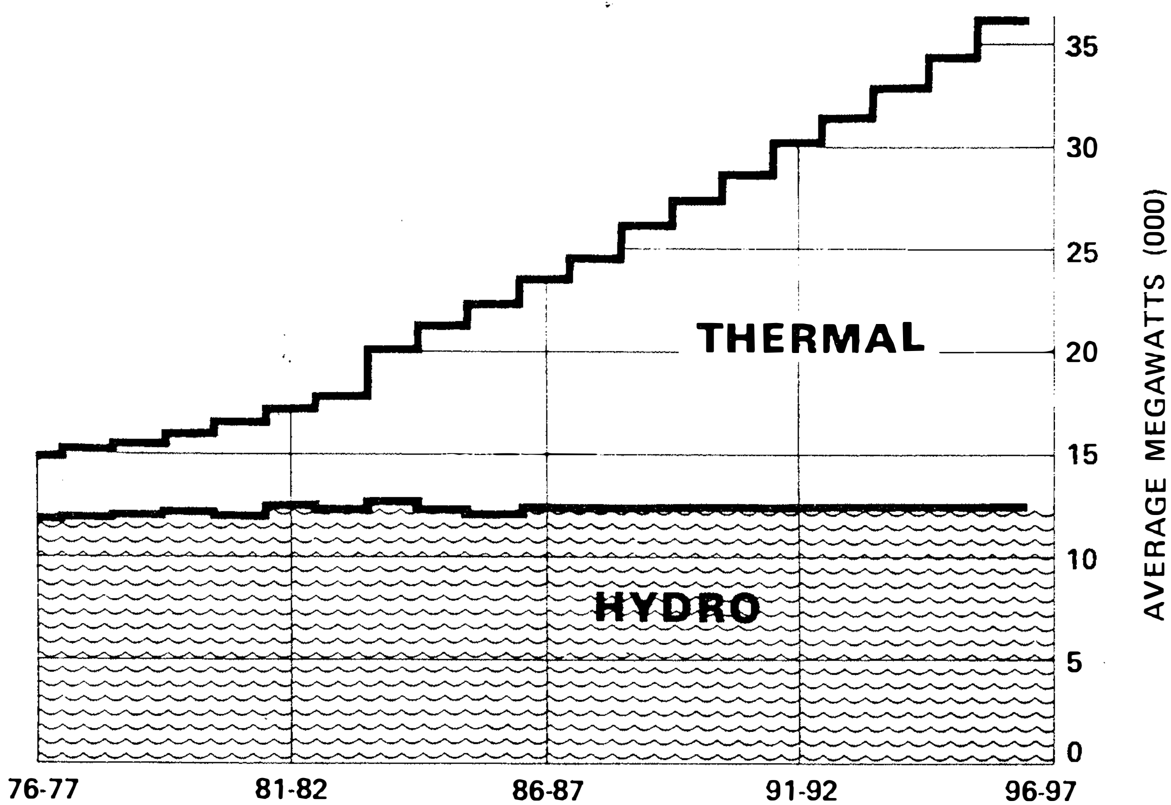
Figure I-1

WEST GROUP AREA OF NORTHWEST POWER POOL

The West Group Area systems include Bonneville Power Administration, Pacific Power & Light Company, Portland General Electric Company, Puget Sound Power & Light Company, The Washington Water Power Company, and 115 public agency customers of BPA. The area presently served by these systems is shaded on the above map.

Figure I-2

ENERGY RESOURCES, WEST GROUP AREA



rates will be required in order for Bonneville to achieve the needed increase in its revenues.

The National Environmental Policy Act (NEPA) of 1969 requires that Federal agencies prepare environmental impact statements prior to taking any major action which could significantly affect the human environment. Per capita consumption of electricity in the Northwest is high relative to the rest of the nation and people in the region depend heavily on electricity and are sensitive to power rates, and it is quite possible that BPA's rate proposal could result in significant impacts to the physical environment in the form of changes in air quality, land use, and water resource use. Significant socioeconomic impacts were also expected and it was anticipated that the size of the proposed increase could make it quite controversial. Consequently, Bonneville has completed this impact statement in conformity with NEPA requirements and according to guidelines established by the Council on Environmental Quality concerning the format and content of environment impact statements. Specifically, NEPA (section 102 (2)(C)) requires that impact statements address:

The environmental impact of the proposed action,

Any adverse environmental effects which cannot be avoided should the proposal be implemented,

Alternatives to the proposed action,

The relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and

Any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

This document presents an explanation of the reasons for BPA's proposed rates and an analysis of the impacts which the proposal or alternatives thereto could have on both physical and socioeconomic characteristics of the human environment. Methods for mitigating the effects of the proposal will also be discussed.

Before going further, and in an effort to avoid possible confusion to the reader, we would like to emphasize the distinction between "rates" and "revenues." The term "revenues" refers to the monies which Bonneville receives from its customers in return for the services which it provides. Revenues will vary from year to year depending on the amount of power sold by BPA and the types of service provided to its customers. A "rate" on the other hand, is an established amount which Bonneville charges for specific units of service, such as a kilowatt of capacity or a kilowatthour of energy.

C. Impacts Discussed in the Statement. The rates which Bonneville is proposing to adopt differ from BPA's existing rates in two basic ways. First, the proposed rates are intended to recover a higher level of revenue than the existing rates. As stated previously, the proposed rates are expected to generate about a 90 percent increase in revenues. Second, the structure or design of the new rates differs in a number of ways from the structure of the existing rates. For example, BPA is introducing a time-of-day pricing feature in its proposed rates. The changes which Bonneville is proposing in rate design would cause rates for some classes of service to increase more than others and will have an effect on the distribution of BPA's revenue burden across its customers.

The analysis of the impact of the proposed rates is presented first from the standpoint of how the increased cost for electricity is likely to affect electricity consumption, as well as the consumption of alternate forms of energy (see Chapter IV). Much of the physical impact projected as a consequence of BPA's proposal is anticipated to occur as a result of a decline in the rate of growth in regional power consumption due to increases in the cost of electricity. This rate of growth in demand may also be affected by other factors such as increased national emphasis on energy conservation and a possible decline in the economy; however, the analyses herein are intended to deal only with those consumption effects created by BPA's rates. Projected consumption under existing rates is used as a base value. Impacts for a variety of alternative power costs are analyzed in terms of the deviation which they would create from consumption under existing rates. It should be emphasized that this change is with reference to the rate of growth which otherwise would have occurred under current rates.

Bonneville has used an econometric model 2/ to estimate the long-term effects of its proposed rates on total regional consumption of electricity. This model is capable of forecasting the effects of changes in average prices on consumption by individual customer groups. It is limited to dealing with average prices, however, and cannot distinguish effects of seasonal or daily rate differentials.

Changes in the projected rate of increase in power requirements would mean changes in the amount of generation facilities required to meet loads at any given time, thereby altering the physical impacts associated with the construction and operation of such facilities. Additional physical impacts could also occur as a result of any changes the proposal might generate in the use of nonfirm energy from BPA for displacement of oil-fired thermal generation in California.

2/ A discussion of the econometric model employed by Bonneville in these analyses is presented in Chapter IV.

Another primary impact of Bonneville's proposed rates would be the effect which the increase would have on utility costs and, therefore, on the increases in retail power rates which BPA's customers would need to impose on their customers in order to recover the cost of the increase in their wholesale power costs. Analysis of these impacts is presented in Chapter V along with the physical and socioeconomic impacts created by these rate increases. Socioeconomic impacts of the increase which are considered include the effects of increased power costs on household budgets and on the use of electricity by residential customers. Also considered are possible effects on agricultural production (primarily as a result of increased irrigation costs) and on business and industry.

Analyses of the impacts of rate design features are presented in Chapter VI. Each of the design concepts considered by Bonneville in developing its proposed rates is analyzed with regard to its potential for impacting the physical or socioeconomic environment. Although the cost increase created by the proposed rates would be the most significant cause of environmental and economic impact, the effect of rate design on the character and distribution of this impact should not be overlooked.

CHAPTER I

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Chapter II
Legal and Historical Basis for Bonneville's Ratemaking Process

The Bonneville Project Act and related legislation gave BPA the authority to transmit and market power from Federal generating facilities. The legislation also contains legal mandates concerning BPA's rate review process, the legal requirements affecting BPA's rates, the relationship of BPA to the Federal Treasury, and the amount of revenue BPA can generate from its rates.

A. Rate Review

1. Rate Review Process. The Secretary of the Department of Energy (DOE) has, under current law, the responsibility to confirm and approve BPA's rates. He has delegated this responsibility to the Federal Energy Regulatory Commission (FERC). Prior to the effective date of any proposed rates, BPA would need to request approval of the new rates. In evaluating the appropriateness of any rate proposal, FERC would consider the effectiveness of the proposed rates in satisfying Bonneville's financial obligations.

The actual rate review process is, of course, more complex than described above. Bonneville begins by conducting a number of studies related to repayment requirements, cost analysis, and rate design. As BPA formulates new rate schedules it may prepare an environmental assessment and, if necessary, an environmental impact statement (EIS). The draft EIS is filed with the Environmental Protection Agency (EPA). Draft rate schedules and a draft rate EIS are then circulated for public and customer review in accordance with Bonneville's environmental review and public involvement processes. During the public comment period which follows dissemination of these materials, interested parties are invited to make suggestions concerning the rate schedules and the draft EIS. Bonneville then updates its cost studies and revises its draft rate schedules, considering suggestions and remarks made during the comment period. The revised proposal is then made public and another comment period is held. Final revisions are made to the proposed rate schedules. The final EIS, revised to reflect public comments, as appropriate, is submitted to the Department of Energy (DOE) for clearance. The EIS is then sent from DOE to the Environmental Protection Agency (EPA). Meanwhile, Bonneville submits the rate proposal to DOE's Office of Resource Applications (RA). At this point the Assistant Secretary may grant interim approval of BPA's proposal pending final approval by FERC. In this case, an order granting interim approval would make the proposed rates effective on December 20, 1979, as scheduled, subject to refund if the rates ultimately approved on a final basis by FERC are lower than the interim rates. If the interim proposal is disapproved by FERC, the interim rates would continue in effect, but Bonneville would then be required to develop new rates within

90 days of FERC's disapproval and, again, to submit them to FERC for consideration.

2. Rate Review Period. The Bonneville Project Act requires that BPA review the adequacy of its power rates at least every 5 years and, if necessary, adjust them equitably. Most of the power sales contracts executed before December 1977 provided that the rates could be changed only on December 20 of every 5th year. Bonneville was thus effectively "locked into" a 5-year rate review period. Until recently, this limitation posed no problems for either BPA or its customers, for the power rates were not essentially changed between 1938 and 1965. In recent years, however, several factors including inflation, construction of new Federal generation and transmission facilities, and the purchase costs of thermal power have combined to cause BPA's costs to increase dramatically. In the face of such rapid cost escalations, the increase in costs over a period as long as 5 years would require an extremely large rate increase every 5 years. As a result, BPA and all of its utility, industrial, and Federal agency customers amended the power sales contracts to allow BPA to review its wholesale power rates on an annual basis and, if necessary, adjust them beginning July 1, 1981.

The object of more frequent rate reviews is to permit a series of smaller rate increases rather than infrequent large increases. Smaller, more frequent rate increases will also enable BPA to track its costs more closely, avoiding serious revenue surpluses or deficits. They will also mitigate the impact on consumers' abilities to pay BPA's increased rates.

B. Legal Requirements Affecting BPA's Rates

1. Widespread Diversified Use. The Bonneville Project Act states that rate schedules "shall be fixed and established with a view to encouraging the widest possible diversified use of electric energy" (50 Stat. 735). Bonneville chose to implement this directive by adopting a "postage stamp" rate and by offering new utility systems a developmental discount. Under Bonneville's postage stamp rate, all customers receiving similar service pay the same rate regardless of the customers' physical locations. Thus, for example, rural communities are not faced with the prospect of paying excessively high transmission rates in order to receive Federal power. Electrification of rural communities throughout the Pacific Northwest was further aided by BPA's developmental discount which was discontinued in 1974 since the goal of electrification of rural communities had been largely accomplished. These two rate features caused Bonneville to extend its transmission facilities to remote areas of the Pacific Northwest and promoted "widespread diversified use of electrical energy."

2. Lowest Possible Rate. Another legislatively imposed criterion is that BPA's power should be priced at the "lowest possible rate . . . consistent with sound business principles" (88 Stat. 1377). Bonneville accomplishes this task by conducting a repayment study (See Section D.3 of this chapter) to arrive at its revenue

requirement. In the repayment study all of BPA's costs are examined and the lowest possible revenue level adequate to recover those costs is determined. A set of rates is then designed to recover the specified revenue.

3. Requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA). The Public Utilities Regulatory Act of 1978 (PURPA), which is applicable to Bonneville, requires that utilities[1/] consider the following six ratemaking standards in the process of developing power rates:

a. Cost of Service

The cost of service standard states that rates are to reflect the costs of providing electric service to various classes of customers. Bonneville conducted its first fully allocated average cost-of-service study for the 1979 wholesale power rate filing. In developing its proposal, BPA allocated costs according to service categories so that the cost-of-service would parallel rate schedules. The service classes include power rates, wheeling rates, and other services and revenues. The power rate categories were further divided into subcategories, such as firm power, reserve power, industrial firm power, modified firm power, firm capacity, firm energy, and nonfirm energy.

b. Declining Block Rates

According to this standard, the energy component of a rate for any class of customer may not decrease as kilowatthour consumption increases unless it is demonstrated that such costs reflect the cost of service. Since BPA has never had declining block rates, BPA's only concern vis-a-vis this standard would be whether it's rates do indeed reflect cost-of-service. Because the cost of energy is rapidly rising, declining bulk rates would appear antithetical to cost-of-service considerations, so it is not likely that Bonneville will have to modify its rates to comply with this standard.

c. Time-of-Day Rates

Rates are to reflect the costs of providing electric services at different times of the day unless such rates are not cost-effective. Bonneville has determined that time-of-day rates are appropriate and cost-effective (only an insignificant amount of new metering equipment is required) and has, as a result, proposed that time-of-day rates be included in its wholesale power rates.

1/ Utilities covered by this Act are those which have annual sales to the ultimate consumer of over 500 million kWh.

d. Seasonal Rates

Rates shall be on a seasonal basis reflecting the costs of providing service during different seasons, to the extent that costs vary seasonally. Bonneville has had a seasonal differential in its rate structure since 1974 and expects to continue with it.

e. Interruptible Rates

Industrial and commercial consumers must be offered interruptible rates reflecting the costs of providing interruptible service. In 1974 BPA introduced the concept of the "availability credit" which was designed to compensate BPA industrial customers who, by using interruptible power, provide BPA with system reserves.

f. Load Management Techniques

Load management techniques are to be offered to consumers where the relevant regulatory authorities have determined that such techniques are practicable, cost effective, reliable, and provide useful energy or capacity management advantages to an electric utility. Bonneville's conservation staff is studying load management. Bonneville has instituted a form of load management with its direct-service industrial customers. Interruptions can be made to facilitate either capacity or energy management. Additionally, Bonneville has an underfrequency load shedding and restoration program to deal with emergency situations. Two automated emergency procedures exist. The first is used for the control of peak problems. The second was developed to control potential problems that may develop when the Northwest is importing large amounts of energy to meet Northwest loads.

On July 19, 1979, BPA held hearings on the PURPA requirements. The hearing officer is preparing his summary of the proceedings and will be making recommendations to the Administrator regarding BPA's determination of whether or not to accept the standards.

C. Financing

Three methods are used to finance the costs of the Federal Columbia River Power System (FCRPS). Bonneville operates on a "self-financing" basis as a result of enactment of the 1974 Federal Columbia River Transmission System Act (Section 9). Under the "self-financing" method, BPA uses its power and transmission revenues to finance its operating costs and, to the extent revenues are available, a portion of its construction program.

The balance of the transmission system construction program is financed through the second method--the sale of revenue bonds to the U.S. Treasury.

The third method involves the financing of that portion of the construction costs of Army Corps of Engineers and Bureau of Reclamation generation facilities allocated to power production through Congressional appropriations. These appropriations, along with operation and maintenance costs and interest costs, must eventually be repaid from the revenues BPA derives from power sales.

D. Revenue Requirement

Bonneville is required to set its wholesale power rates at a level sufficient to recover the cost to the Government of producing, purchasing, and transmitting electric energy.

1. Legal Basis for BPA's Revenue Requirement The basic requirement to recover costs is found in Section 7 of the Bonneville Project Act (50 Stat. 735) which provides that, "Rate schedules shall be drawn having regard to the recovery of the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years."

Virtually the same language as quoted above is also contained in Section 9 of the Federal Columbia River Transmission System Act (88 Stat. 1377). This Act, which placed BPA on a "self-financing" basis by authorizing the use of sales receipts and revenue bond proceeds to finance the BPA program, further provides that rates be set," . . . at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of, and interest on all bonds issued and outstanding pursuant to this Act, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith."

The aforementioned statutes, however, are not specific on many points. For instance, a "reasonable period of years" is not specifically defined, nor are "sound business principles" described. Neither is there any general requirement for the payment of interest on the investment in power facilities financed with appropriated funds, although the authorizations of several individual power projects provide for the payment of interest. Consequently, the details of the repayment policy have had to be established through individual project authorization and administrative interpretation of the basic statutory requirements. The pattern of a 50-year repayment period for project costs allocated to power and associated interest costs was set in the Federal Power Commission interim cost allocation order for Bonneville Dam, February 8, 1938.

2. Repayment Criteria The administrative interpretation currently applied to BPA's repayment criteria was set forth in the departmental manual of the Department of Interior. This

interpretation has now been adopted by the Department of Energy. In brief, the repayment policy as currently in effect provides that BPA's total revenues from all sources be sufficient to:

a. Pay all costs annually of operating and maintaining the Federal power system.

b. Pay the cost each fiscal year of obtaining power through purchase and exchange agreements.

c. Pay when due the interest and amortization on outstanding revenue bonds sold to the Treasury.

d. Pay interest each year on the unamortized portion of the commercial power investment financed with appropriated funds at the interest rates established for each generating project and for each annual increment of such investment in the BPA transmission system.

e. 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 on construction costs. These repayment periods range from 40 years to 66 years with 60 years being applicable to most of the irrigation projects. Irrigation costs are repaid without interest. (P.L. 89-448 authorizes the payment of irrigation costs from revenues of the entire power system. This is the so-called "Basin Account" concept. P.L. 89-561, approved on September 7, 1966, amended P.L. 89-448 to provide several limitations on the repayment of irrigation costs from power revenues. These are as follows: (a) the irrigation costs are to be paid from "net revenues" of the power system, with net revenues being defined as those revenues over and above the amount needed to cover power costs and previously authorized irrigation repayment; (b) the construction of new Federal irrigation projects will be scheduled, i.e., deferred, if necessary, so that the repayment of the irrigation costs from power revenues will not require an increase in the BPA power rate level; and (c) the total amount of irrigation costs to be repaid from power revenues shall not average more than $30 million per year in any period of 20 consecutive years.)

f. Repay each dollar of the power investment in the Federal generating projects within 50 years after it becomes revenue producing (50 years has been considered a "reasonable period" as intended by Congress);

g. Repay each annual increment of transmission investment, previously financed with appropriated funds, within its estimated service life (35 years is the approximate average service life of the transmission facilities, and hence a "reasonable period");

h. Repay the investment in each replacement of a power generating facility within the service life of the facility. In accomplishing the repayment of the power investment, the investment bearing the highest rate of interest may be amortized first to the extent possible, while still completing repayment of each increment of investment within its prescribed repayment period.

3. Power System Repayment Study. The adequacy of power rates to meet the repayment criteria is determined by preparing a power system repayment study. This study projects estimated revenues and costs over the repayment period for the entire power system in order to determine if current rates will allow recovery of all costs. Because BPA operates on a repayment basis rather than on a cost-accounting basis, its revenues may not equal its expenses in any given year. However, over the entire repayment period the revenues should be just adequate to cover all costs. If estimated revenues fall short of this objective a revenue increase is needed.

E. Summary

Bonneville is legally obligated to meet its responsibilities as outlined in this chapter. Bonneville's obligations include periodic review of its rates, setting of the rates at a level which will allow it to continue on a self-financing basis, design of rates which are equitable while promoting widespread, diversified use of electric energy, and satisfaction of it's repayment responsibilities. These responsibilities form the core of many of Bonneville's actions and policies. However, Bonneville has some administrative and contract discretion. This was clearly demonstrated in the recent revision of contracts to provide for a more frequent rate review period instead of the previously permitted 5-year rate review period.

Although there is currently no legal provision for Bonneville to implement some of the alternative revenue levels discussed in the next chapter, they should, nonetheless, be considered. It is possible that as power costs rise, BPA's legal responsibilities could change, causing these revenue levels to become viable alternatives to repayment, as is currently defined.

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Chapter III
Description and Quantification of Revenue Alternatives

As explained in Chapter II, Bonneville is legally required to set its wholesale power rates so as to recover the cost to the Government of producing, purchasing, and transmitting electric energy. This chapter will describe and quantify several different revenue levels, including the proposed revenue level which BPA considers adequate to meet repayment requirements. Bonneville has some degree of flexibility in determining how the repayment requirement is met. Modifications to the existing revenue requirement are exemplified in the following revenue level alternatives.

A. <u>No Action Alternative</u> (zero percent revenue increase).

1. <u>Description of the Alternative</u>. Under the "no action" alternative BPA would maintain its existing rate structure. As the law now stands this alternative is not feasible because the proposed rates would fail to generate revenues sufficient to satisfy BPA's financial obligations.

2. <u>Quantification of the Alternative</u>. If BPA were to maintain its current rates, the resulting revenues for calendar years 1980 and 1981 would be as indicated below. The revenues required for repayment in these years are also shown.

TABLE III-1
Comparison of Revenues Under Current and Proposed Rates

Calendar Year	Revenue Under Current Rates (inadequate for repayment) ($000)	Revenue Under the Proposal (adequate to meet repayment) ($000)
1980	$345,310	$645,747
1981	$357,765	$674,168

3. <u>Effects of the Alternative on BPA</u>. It is apparent from these revenue estimates that Bonneville would experience an extremely serious revenue shortage in the absence of a rate increase.

Continuation of current rates through July 1981 would affect both payment for the net-billed thermal plants1/ and payment of other BPA obligations. The initial impact on net-billed payments would be on the bond ratings for financing these plants. The bonds have been sold based on the assumption that BPA would have sufficient revenues to service the bonds. Without sufficient revenues to meet total repayment requirements, the interest rate for future bond sales could be higher due to a reduction in the bond rating from AAA. If BPA's financial situation were perceived to be severe, the bonds, which will be issued to finance completion of the plants, might go unsold.

The second impact relates to payments on existing bonds. Net-billed payments have first priority on BPA revenues because Bonneville is obligated to make net-billed payments prior to any payments by BPA to the Treasury for repayment of the FCRPS investment, the U.S. Bureau of Reclamation and Army Corps of Engineers project costs, and the bonds issued pursuant to the Transmission Act. For the effective period of the rates (through July 1981), BPA would have sufficient revenues to cover current net-billed cost obligations. However, by 1983 current rates would produce revenues insufficient to meet even net-billed payment obligations.

The primary impact during the 1979-81 period would be on payment of BPA revenue bond interest and amortization, operation and maintenance costs of generation and transmission, amortization of power investments financed with appropriated funds, and irrigation repayment assistance. Payment of all these costs has priority below that of payment of net-billed obligations. Some of the above payments could not be made during the 1979-81 period. Bonneville would default on its payments to the Treasury and would have insufficient funds to operate and maintain the Federal Columbia River Power System. Bonneville's only recourse, in lieu of "going out of business," would be to request that Congress appropriate funds for continued operation of the system. This would be contrary to the intent of the Federal Columbia River Transmission System Act of 1974 which authorized BPA to operate on a self-financing basis.

1/ As part of the hydro-thermal power program, BPA became involved in net-billing arrangements for several plants built or currently under construction by a coalition of utilities (participants). In return for paying the project costs by crediting the project participants' power bills for the participants' shares of the projects' expenses (hence, net-billing), BPA acquired rights to the output of the plants.

4. Environmental Impacts of the Alternative. This revenue alternative would be the most environmentally damaging of all those considered. The impacts on air quality, land use, radiation exposure and occupational injuries would exceed those of any other alternative (see Tables IV-5 and IV-7 for quantification of these impacts). Socioeconomic impacts, on the other hand, would be lower than for any of the other revenue alternatives considered. Consumption of electricity might well exceed the forecasts, as the forecasts were based on the presumption that BPA would raise its rates by approximately 90 percent in late 1979. If Bonneville were not to raise its rates, electricity could become (assuming that a utility's other costs increased at about the overall inflation rate) a relatively cheap commodity, and this revenue alternative might stimulate the use of electricity as well as encourage purchases of electricity consuming appliances.

B. Revenue Level without BPA Financing for Thermal Plants Under Construction (30 percent revenue increase).

1. Description of the Alternative. A major portion of BPA's proposed increase is intended to cover costs associated with two net-billed nuclear projects under construction by the Washington Public Power Supply System (WPPSS) and which BPA is contractually obligated to pay. In return for paying the project's costs, Bonneville receives the output of the plants. Because the nuclear projects will not be completed by the "dates certain" (dates BPA and WPPSS believed, at the time the projects were conceived, to be the latest possible date for the plants to commence operations), Bonneville must pay debt service on those plants even while they remain inoperable. As a result, Bonneville and WPPSS proposed that WPPSS finance the debt service that BPA is currently obligated to pay on WNP (WPPSS Nuclear Projects) 1 and 2 until the dates of commercial operation. If this arrangement had been agreed upon by all 104 participants in these plants, BPA would have been able to reduce its revenue requirement substantially.

For many years regulatory agencies and utilities have addressed the issue of whether to include in rates the costs related to plants under construction, including the debt service on funds borrowed to finance construction. The principle behind the issue is that the ratepayer should not be required to pay the cost related to a project under construction and not yet in service. If the construction of the WPPSS plants had progressed on schedule there would have been no question about whether BPA should include the costs of WNP 1 and 2 in its 1979 rate proposal. However, because the scheduled dates of commercial operation of these projects have been changed, due to construction delays, to dates beyond the rate review period, the alternative which allows WPPSS to issue subordinate bonds to finance those costs was proposed.

2. Quantification of the Alternative. If all the project participants had concurred with the change in debt service financing, BPA would have been able to hold its revenue increase to approximately 30 percent.[1/] Under this alternative, BPA would have collected revenues amounting to approximately $449 million in calendar year (CY) 1980.

Had this contract amendment been adopted, Bonneville's revenue increase would, primarily, have reflected increased costs associated with inflation, new Federal facilities and the operation of the Trojan power plant (also a net-billed plant). Based upon its own analyses, Bonneville supported the position that WPPSS should finance these costs until the dates of actual commercial operation of the plants. However, two utilities rejected the proposal. In their opinion it is fiscally questionable to issue additional bonds to pay the debt service on construction bonds. In addition, they felt that utilities and utility customers need to face the fact that generation costs are rising rapidly so that such knowledge can be incorporated into planning related to energy use.

3. Effects of the Alternative on BPA. Had this alternative been adopted, BPA could have reduced its 1979 rate increase from 90 to approximately 30 percent. Bonneville could still have met all of its repayment obligations as currently defined. However, BPA would have had to start paying for both the additional financing costs and the original construction costs when the power plants actually started generating power. The resulting revenue level after 1985 would then have been higher than it would be under the 90 percent proposal which already includes some of these costs. Nonetheless, despite the higher costs in later years, an economic analysis justified approval of the 30 percent increase proposal based on long-term economic benefits.

4. Environmental Impacts of the Alternative. Bonneville believes that this alternative might be the most environmentally acceptable of all the revenue levels considered in that physical impacts are slightly less than under the "no action" alternative, but socioeconomic impacts are not nearly as great as under any of the alternatives discussed later in this chapter. A revenue increase of this magnitude would generally raise electricity prices at the retail level, causing customers to begin conserving (thus reducing the physical impacts of electricity, oil and gas use), but a 30 percent increase would not likely have the

1/ At the time the proposal for the additional WPPSS financing was formulated, BPA's repayment studies had indicated that the revenue increase under the proposal would have been approximately 40 percent. However, further refinements made in the final repayment study demonstrated that the increase would have been in the range of 30 percent had the additional financing been approved.

disruptive socioeconomic consequences associated with higher revenue levels. A revenue increase of approximately 30 percent would be consistent with President Carter's wage and price guidelines1/. It should be remembered that BPA has had no increase in its power rates since 1974. During that period of time the Consumer Price Index (CPI), a standard economic barometer, has risen more than 47 percent.2/ Naturally the inflation rate for the power industry differs from that reflected by the CPI which represents a "market basket," but clearly the 30 percent rate increase is in line with overall price trends. In fact, had BPA had a 5.4 percent rate increase every year since 1974, the resulting rate increase would have been almost identical to that shown under this alternative.

C. Reduced Revenue Level (83 percent revenue increase).

1. Description of the Alternative. This alternative considers possible modifications to the repayment criteria which would reduce BPA's revenue requirement.

Under this alternative, Congressional mandates regarding self-financing and repayment of Federal costs are treated as binding. Bonneville's obligation to repay nonpower costs (irrigation assistance) and details concerning BPA's repayment policy are varied under this alternative.

This alternative represents an attempt by Bonneville to make reasonable and relatively minor alterations to existing policies and directives under which BPA operates. A case can, of course, be made for examining any number of variations relating to BPA's revenue requirement, but Bonneville considered the changes described below as the most likely to be approved by Congress. Changes in the self-financing mandate, for instance, are not likely in this era of public concern with government spending.

2. Quantification of the Alternative. There are a number of possible ways to reduce the revenue requirement. Bonneville has already made changes (reflected in the actual rate proposal) which have reduced the revenue requirement to the lowest possible level permitted by law and Department of Energy policy. The following two changes would, however, represent an alternative

1/ Bonneville is, however, bound by its statutory obligations to recover its revenue requirement. The revenue requirement is cost-based and is independent of the President's guidelines.

2/ Figures for Urban Wage Earners and Clerical Workers Apr '74 (144.0) to Apr '79 (211.8) for the United States. Regional figures are not available, but comparable data for both Portland and Seattle are higher than the national average.

which would further reduce the revenue requirement. The third change is not considered by BPA to be "reasonable" and is not included in the quantification of this alternative, but is mentioned because it would significantly affect BPA's revenue requirement.

a. Eliminate the requirement to repay irrigation costs. Bonneville currently repays the portion of construction costs of Federal reclamation projects which is beyond the repayment ability of the irrigators. A possible argument in favor of changing this policy could be that the American public at large has more to gain from this subsidy than does the ratepayer of selected utilities in the Pacific Northwest. However, because the dams are located in the Pacific Northwest and Congress apparently wished to recover the costs of these projects from those who have benefitted directly from them, Bonneville is obligated to include the cost of irrigation repayment assistance in its revenue requirement. Elimination of irrigation repayment would reduce Bonneville's revenue requirement by approximately 1 percent.

b. Amortize Federal generation facilities over an 85 year period. The current average service life of generation facilities is 85 years. Bonneville's transmission system is already being amortized on a service life basis (35 years) and it could be argued that the repayment period for generation facilities should be changed from the 50-year basis specified by current repayment policy to an 85-year "service life" basis.

If both the irrigation and service life changes, discussed above, were made in repayment policy the net effect would be to reduce BPA's required 90 percent revenue increase to approximately 83 percent.

c. Change the allocation of project costs. The total cost of multipurpose water resource projects is apportioned to various purposes, including navigation, flood control, irrigation, and power. Cost allocations are made for the Federal Columbia River Power System and power revenues are expected to repay all costs allocated to power as well as that portion of the irrigation construction costs which exceeds the irrigation users' ability to repay.

As an alternative, BPA's power revenues could repay a smaller portion of project cost, thus reducing revenue requirements.

3. Effects of the Alternative on BPA. Bonneville would be required to seek Congressional approval of the irrigation cost and amortization changes. If Congress were to accept the arguments in favor of change, the requisite accounting adjustments could be made.

The change in amortization policy would cause BPA to have a negative amortization in FYs 2014 - 2016. This phenonemon is caused by the fact that purchased power costs are included in the repayment study only for the presumed 35-year lives of the nuclear plants. This causes much of the amortization of the Federal investment to be deferred until 2020 which is after the purchased power costs have been repaid. By lowering revenue requirements to approximately 83 percent by lengthening the repayment period to 85 years, the amortization would become negative in FYs 2014 - 2016. If BPA cannot afford to meet all of its interest expense in any given year, negative amortization occurs because any unpaid expense must be added to BPA's unamortized investment, or the principal upon which interest is to be paid. As a result, the long-run effect of negative amortization would be to raise BPA's rates.

Departmental policy, to date, seems to preclude basing proposed rates on the prospect of such a substantial amount of negative amortization. If Bonneville were to implement this alternative, BPA would have to either seek a change in this policy or effect the change subject to the constraint that no negative amortization would occur. Because a departmental policy change would allow for a greater revenue reduction, the alternative quantified herein assumes that the policy would be changed.

There would be no significant impact on Bonneville as a result of implementation of the alternative, but all taxpayers (rather than Northwest power customers of BPA) would have to shoulder the cost of the irrigation payment.

4. Environmental Impacts of the Alternative. The reduced revenue level alternative's physical impacts on the environment are lower than for any alternative already considered. However, the improvement in the physical environment is counterbalanced by adverse socioeconomic impacts. Most affected at this revenue level will be low income domestic users and farmers who irrigate their land with sprinkler irrigation systems. These impacts are discussed in detail in Chapter V.

D. Proposed Revenue Level (90 percent revenue increase).

1. Description of the Alternative. The proposal reflects BPA's commitment to meet its obligations as set forth by Congress. Bonneville conducted a repayment study and determined that a revenue increase of 88 percent is required to enable BPA to meet its payout obligations under current repayment policy. The proposed wholesale power rates, plus the intended increase in transmission rates (see 44 FR 30405, May 25, 1979), would produce an estimated 90 percent increase in total revenues throughout the repayment period. The rate structure has, however, been somewhat

modified from that used in the 1974 rates. Consequently, while the overall revenue increase will be 88 percent, the actual rate increase in any year or to any particular customer may vary.

2. Quantification of the Alternative. Under this alternative revenues in calendar year 1980 should increase from approximately $345 million which would be received under current rates to approximately $645 million. These rates would be effective until July 1, 1981, the next date BPA is permitted, under the terms of its power sales contracts, to adjust its rates.

There are several basic factors underlying the need for this revenue increase. Costs have been increasing due to inflation. Bonneville's operating costs since the last rate increase in 1974 have been increasing at a rate of about 9½ percent per year. (Summary Financial Data (1974, 1978)) The cost of recently completed Federal power facilities is substantially higher than the cost of older facilities, many of which were built years ago when costs were much lower.

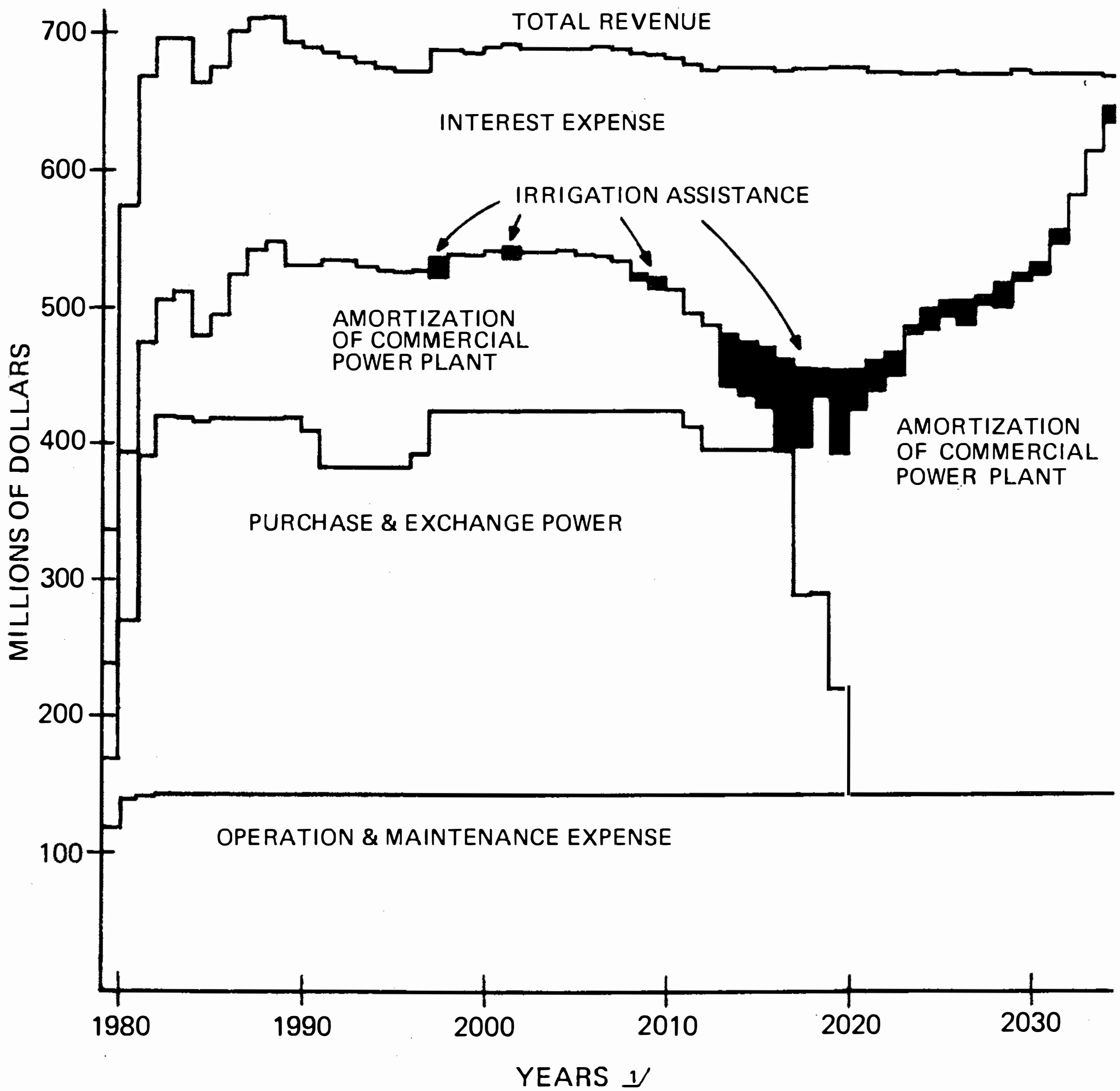
A large portion of the revenue increase would be to cover the cost to BPA of purchasing power from three nuclear powerplants which have either been completed or are currently under construction. The costs of these nuclear plants are substantially higher than the hydroelectric projects which have been supplying most of BPA's power needs for many years.

Bonneville is currently paying for a 30 percent share of the Trojan nuclear plant constructed by the Portland General Electric Company. Bonneville's cost for this power in each of the next several years will be about $30 million per year. Bonneville has also contracted to purchase either all or a large percentage of the capability of three nuclear plants being constructed by the Washington Public Power Supply System (WPPSS). When these plants are completed in the early 1980's, BPA's payments for the purchase of power from the WPPSS plants will exceed $400 million per year. As the revenues from the present rates are approximately $345 million per year, the need for much greater revenues to pay for the cost of both existing and new Federal facilities plus power purchases becomes clearly evident.

Figure III-1 shows BPA's anticipated expenditures on each repayment item in each year of the repayment period with the revenues from the proposed rates.

3. Effects of the Alternative on BPA. The revenue level selected for use in the rate proposal represents the most appropriate of all the alternatives considered by BPA. The revenue will be adequate to meet all of BPA's repayment obligations without jeopardizing Bonneville's commitment to sell its power at the "lowest possible rate consistent with sound business principles."

Figure III–1



USE OF BPA REVENUES

1/Fiscal Year Data: Oct 1—Sept 30

Legally this alternative should ensure that Bonneville's rate review process with the Department of Energy and with FERC will be faster and smoother than it would have been had BPA chosen to attempt to modify its repayment policy and select another revenue level.

4. Environmental Impacts of the Alternative. The proposed revenue level is expected to have environmental impacts which closely resemble those of the 83 percent revenue alternative. It should be noted, however, that the gains in air quality and reduction in land use, radiation exposure, and occupational injuries are fairly minimal--for each physical impact category the improvement is never more than 1.1 percent over the "no action" case. In contrast, the socioeconomic impacts of a 90 percent revenue alternative are fairly severe--in the short run irrigated acreage may be reduced by 3 percent. (See Table V-11.) A 90 percent wholesale power rate increase translates to a 50 percent increase at the retail level. Low-income domestic users will be hurt both by their increased power bills and by the fact that business and industry will pass their increased costs along to consumers.

E. Increased Revenue Level (195 percent revenue increase).

1. Description of the Alternative. This alternative would change several of BPA's repayment criteria in ways which would cause BPA's rates to rise. As in the discussion of BPA's "Reduced Revenue Level" in Section C of this chapter, the underlying principles upon which BPA's repayment criteria were established would not change, but the criteria themselves would be modified to reflect a revenue level which would be higher than that actually proposed.

2. Quantification of the Alternative. The following four changes in repayment policy would raise the revenue requirement. The first two represent a return to the method by which Bonneville calculated its revenue requirement in the past.

a. Include the anticipated variable[1/] costs and revenues associated with the WPPSS plants. Inclusion in the repayment study of the revenues and variable costs of WNP 1 and 2 (such as for operation and maintenance and fuel) would increase BPA's revenue requirement because the revenues received from the projects would be less than the costs of operating the facilities.

1/ Variable costs are those costs which vary as production levels change. For example, fuel costs are variable costs while depreciation expense is a fixed cost which will be incurred regardless of whether the plant is operating.

b. Include the anticipated costs and revenues associated with Federal facilities, which are either authorized or already under construction. This modification is similar to that discussed above. The primary difference is that this change refers to Federal facilities, the other to non-Federal facilities. Previously, Bonneville included in the repayment study all costs and anticipated revenues from all authorized projects. Recently however, BPA's General Counsel rendered a legal opinion on the matter in which it was stated that BPA was not required by law to include these revenues and costs. As a result, BPA modified its method of determining its repayment obligations to agree with the General Counsel's opinion. If BPA were to include these revenues and variable costs associated with authorized Federal projects not to become operational until a future rate period, BPA's revenue requirement would increase.

c. Have Bonneville pay the current interest rate for all facilities. Bonneville is currently paying interest rates of approximately 9½ percent on bonds sold to finance new transmission facilities. Because a number of new hydro projects which are just now being built were authorized many years ago, the stated interest rate for these projects is often very low--approximately 2½ to 3¼ percent. Assuming that the Treasury would finance these projects with long-term bonds, the current cost would be approximately 8.8 percent. Because the Treasury continually issues bonds, some have argued that BPA should use the current interest rate to determine interest expense. Under this revenue alternative BPA would pay the current interest rate on all its outstanding debt for generation facilities. Overall, this alternative would increase BPA's revenue requirement to a level 195 percent higher than the present revenue level.

d. Internalize all external costs. If utilities are to reduce the environmental impacts of their operations, they must generate sufficient revenues to cover environmental mitigation costs, yet sell their product at a price that allows the most economic utilization of the total resources committed to producing electricity (Perkins, 1975, p. 151). These environmental and ecological costs, known as external costs, are produced by the generation, transmission, and distribution of electricity and are costs imposed on society that are external to the operation of the economy in such a way that compensation for them is not normally obtained. Externalities include the effect of effluents on human health, animals, plants, and the life of materials, and maintenance of the quality of air, water, and land. The nature of externalities makes it difficult, if not impossible, to place a dollar value on them (Lave and Silverman, 1976, discuss this topic).

Current attempts to deal with external costs have usually taken the form of government regulations on maximum allowable levels of effluents either at the point of release or in the general environment. For example, such regulations result in additional industry costs for stack gas cleanup in coal plants, cooling towers for nuclear plants, fishery enhancement programs, and water treatment facilities. Costs such as these are included in the price of electricity and increase the amount of revenue BPA requires.

Alternate methods for dealing with external costs include taxing pollution or using a discharge permit process to limit the level of pollutants released to an amount which would not exceed the natural assimilative capacity of the environment. With a tax, the utilities would have the choice of reimbursing society through the tax payment or avoiding the tax by paying for facilities to eliminate the pollution. Conversely, such charges might provide tax credits for enhancements and benefits created incidental to hydro projects, e.g., recreational aspects.

Another method is to set up something like an Environmental Trust Fund (Tybout, 1972, p. 41). Effluent charges would be paid into this fund and expenditures would be made from the fund to the public for compensation of external costs. An example of this is BPA's Fishery Mitigation Program.

3. Effects of the Alternative on BPA. The first two changes represent a return to the method of conducting a repayment analysis used in BPA's 1974 rate review. Recent legal interpretation of Bonneville's obligations, however, enabled BPA to change this policy to exclude from its repayment study the revenues and variable costs associated with thermal purchases and investment, interest, and operation and maintenance costs for future Federal projects not completed during the rate period.

Because some externalities are already included in BPA's rates and others are virtually impossible to quantify, the externality consideration is presented primarily in order to note that as environmental laws change, external costs may raise BPA's revenue requirement.

The change in interest rate policy would cause BPA's rates to fluctuate as the U.S. Treasury long-term interest rates rise and fall. The stability of BPA's rate structure would be threatened and, at least in the near term, the change would cause BPA's rates to increase substantially.

4. Environmental Impact of the Alternative. The 195 percent alternative would have a dramatic impact on the socioeconomic health of the Pacific Northwest. The impact on retail rates would be such that many retail rates would double (100 percent price increase at the retail level). Adequate measures for

mitigating the impact of the rate increase on low-income users would become essential if this revenue alternative were adopted. Otherwise, these consumers would be required to drastically alter their lifestyles in order to live within their means. One such mitigating measure, however, is within a utility's power and is already being adopted by many of BPA's preference customers. By changing flat energy rates rather than declining block rates,1/ the burden of the rate increase falls on those who consume the most electricity, while offsetting the burden of the low users. Of course, should a low-income user be a large consumer, a flat rate structure could exacerbate his problems. It should also be kept in mind that if a utility has a flat rate, the impact of conservation on the utility's revenues will be more severe than it would be with a declining block rate structure. The effect would, of course, be greatest if the utility were to have inverted rates. The overall effect of a 195 percent revenue increase will depend to a large degree on how the retail utility incorporates the additional wholesale power cost into its rate structure.

From an environmental point of view, however, this alternative has the benefit of having the lowest physical impacts of all the revenue alternatives previously considered.

F. Revenue from Long-Run Incremental Cost (LRIC) or Marginal Cost Pricing (895 percent revenue increase).

1. Description of the Alternative. Another approach to the determination of the appropriate revenue level would be one which considers only the cost of additional power production rather than historical, embedded costs.

The theory of long-run incremental cost or marginal cost pricing is that if the price of all commodities is set equal to their marginal cost, then available resources will be allocated to the optimum satisfaction of all consumers. Marginal cost pricing provides a signal to society of the cost of producing one additional unit of a good or service. The principle is one of cost causation. Those who cause costs to be incurred should pay the costs of providing that service.

1/ Under a flat rate a consumer pays the same rate for each kWh of electricity he uses, regardless of how much he requires. Under a declining block schedule, however, the customer pays less per kWh as his usage increases. Under inverted rates, a consumer is charged more per kWh for power as his consumption increases.

In relation to the pricing of electricity, the purpose of marginal cost based rates is to charge the correct economic price. Once these rates are established, consumers are able to make more knowledgeable decisions concerning how much electric service to purchase and when to purchase it.

If the marginal cost of production were lower than the average cost (total cost divided by total units of output) and BPA were charging rates based on marginal cost, BPA would not receive enough revenue from its sales to pay the costs itemized in Section D.2 of Chapter II, "Repayment Criteria." On the other hand, if the marginal costs were higher than the average costs, the present situation with regard to BPA's costs, a marginal cost based rate would generate revenue which would exceed BPA's repayment requirement. Though the excess revenues would create a problem under current repayment criteria, the economic efficiency aspects of long-run incremental cost pricing warrant further consideration of the approach.

2. Quantification of the Alternative. Bonneville conducted an LRIC study to evaluate this alternative. The basic methodology used by BPA followed the procedure developed by National Economic Research Associates (NERA). This study represents the first application of the marginal cost concept to BPA and was conducted to determine the incremental costs BPA is incurring for new generation and transmission. The two issues BPA considered in the study were the measurement of long-run incremental costs and application of these costs to rates. For a detailed discussion of the methodology used in developing BPA's LRIC rates, see BPA Long-Run Incremental Cost of Service and Rate Study (BPA, July 1979).

The rates derived in the LRIC study were applied to BPA's projected 1980 sales. The 1980 marginal cost revenue was $2,299,000,000 or approximately $1,654,000,000 higher than the revenue generated under the proposed rates which are just adequate to meet repayment (as currently defined). The revenue level does not account for a reduction in electricity use, a likely occurrence if marginal cost rates were charged.1/

A modification of the results of LRIC pricing would be to adjust the rate to meet BPA's revenue requirement. The adjustment would require that cost components be adjusted downward in a fashion

1/ Because marginal cost rates are so much higher than the average cost rates currently in effect, it is difficult to predict with any certainty how much conservation might occur under LRIC pricing. As a result, this analysis did not attempt to estimate the actual revenues which Bonneville would receive under marginal cost wholesale power rates.

that did not distort demand patterns. This could result in application of the "inverse elasticity rule" (IER). Elasticity is a term used to describe the degree to which quantity demanded will change with a given price change. Demands which respond to price are termed "elastic," while demands which remain roughly constant in quantity, irrespective of price, are termed "inelastic." Under this approach, the larger the absolute value of the price elasticity of a class of customer, the less its rates would deviate from that obtained from pricing at marginal cost. In other words, the class most sensitive to price would receive a price signal which most accurately reflected marginal cost, while those who will not change their consumption patterns would be charged a lower rate. (For a detailed discussion of IER, see Sarikas and Herz, 1976, Appendix B.)

3. Effects of the Alternative on BPA. Because BPA's marginal cost of electricity is very high in relation to BPA's average cost, the effective increase in rates would amount to approximately 895 percent.1/ The resulting revenues would clearly greatly exceed those required by BPA to meet its financial obligations. If the law were changed to enable BPA to adopt this alternative, BPA would be required to determine what it should do with its excess revenues. For example, they could be turned over to the Federal Treasury to help offset the Federal deficit or they could be used to finance research into alternative energy systems. Excess revenues could also be returned to consumers through various methods. For example, the revenues could be used to purchase insulation and storm windows for each customer.

4. Environmental Impact of the Alternative. In terms of the physical environment, the marginal cost alternative is most assuredly the best alternative. In 1997, air quality in general is expected to be measurably improved over the "no action" alternative. Particulates are expected to be 92 percent of the "no action" levels, nitrogen oxides 99 percent, sulfur dioxides, 90 percent and hydro carbons 97 percent. The biggest improvements in the physical environment would be in solid waste at 86 percent of the "no action" level, land use 95 percent, radiation exposure 86 percent, and occupational injuries at 89 percent. The reduced levels cited above would probably be even lower as the econometric model which generated the figures relating to fuel consumption was limited to consideration of fuel oil, natural gas, and electricity from hydro or thermal plants. Under a marginal cost alternative, it is most likely that solar, wind, and geothermal power will play an important role in the

1/ This figure is based on the average rate paid by BPA's preference customer under the existing pricing and the average rate expected to be paid under LRIC pricing. The marginal cost revenue figure mentioned on the previous page includes revenue from all rates under LRIC pricing.

electricity supply picture.[1] Environmental impacts of these sources have not been clearly identified and quantified, but in general they should be significantly less than for existing, conventional sources. Major impacts of these newer, virtually untapped sources are apt to be primarily visual (solar collectors on roofs, windmills, etc) and on land use (geothermal). Employment in these developing technologies would probably increase dramatically, an off-setting impact to the otherwise highly adverse socioeconomic consequences of the alternative.

1/ If BPA's projections of natural gas and fuel oil prices are low, the presumption of increased use of alternative energy sources is even more reasonable.

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Chapter IV

Bonneville's Econometric Model - Analysis of the Effect of Each Revenue Alternative on Regional Power Consumption

This chapter will explore the effect that each of the revenue levels discussed in Chapter III would have on regional consumption of electricity, oil, and natural gas in the year 1997 by which time the full effect of the rate increase on consumption should be realized. The analysis is presented for the economy as a whole and is not intended to predict how individual consumers would respond to the various alternative revenue levels. The basis for the regional analyses is an econometric model developed by BPA, also described in this chapter. Readers who are not interested in the effect of BPA's increase on regional consumption may wish to turn directly to Chapter V where the analysis focuses on the impact of a rate increase on individual consumers.

In order for BPA to assess the long-run effects of various revenue levels on the future demand for electricity, oil, and gas in the Pacific Northwest, it was necessary to develop an econometric model. This model applies statistical techniques to a given set of economic conditions in order to predict the value of a particular variable (in this case, consumption) at any given point in time. Table IV-1, page IV-17, summarizes the results of the econometric study. It should be noted that these results are based on "average" rates, that is, the impacts of various rate designs interacting with particular revenue levels are not analyzed. Rate designs are discussed in Chapter VI. Actual consumption in 1997 will quite likely depend, at least in part, on the rate design features of the power rates.

A. Discussion of BPA's Econometric Model. Described below in some detail is the econometric model developed by BPA. This model analyzes the effects of various revenue levels which BPA has adopted, or might adopt at some future date, on power consumption by BPA's customers.

Impacts from any action initiated by BPA which affects electric rates or power availability are felt in many sectors of the economy, both inside and outside of the Pacific Northwest. Since the process of identifying and measuring those impacts is complicated, it is imperative that some order be brought to an analysis of cause and effect relationships. One accepted method of systematic evaluation is the use of a simulation model. The simulation process allows the evaluator to use varying data, assumptions, and projections to examine probable impacts from a variety of alternative policies in a systematic way. (For examples of energy modeling, see Vogely, 1973; Searl, 1973; Macrakis, 1974; and Baughman and Joskow, 1974.)

All electrical energy producers in the Pacific Northwest have been included in the evaluation process. The basic input data to the model are existing supplies of and demand for electrical energy in 1977 for BPA, investor-owned utilities, and preference utilities. By varying assumptions and data on supply and demand, a spectrum of alternative senarios of the future demand-supply balance can be generated from the simulation model. The data output for various alternatives can then be analyzed to determine the probable economic, social, and environmental impacts on the region. The simulation model is designed to answer a variety of questions about demand and supply of electricity in the Pacific Northwest for the period 1978-1997. The usefulness of the process is dependent upon the types of questions which can be answered. Some of those questions are:

What will be the generation, transmission, and distribution costs of electric energy for BPA, public and investor-owned utilities at various levels of output between now and 1997?

How will the price of electricity influence regional power demand?

At any given price of electricity, what portion of demand will be attributable to residential as opposed to commercial or industrial customers?

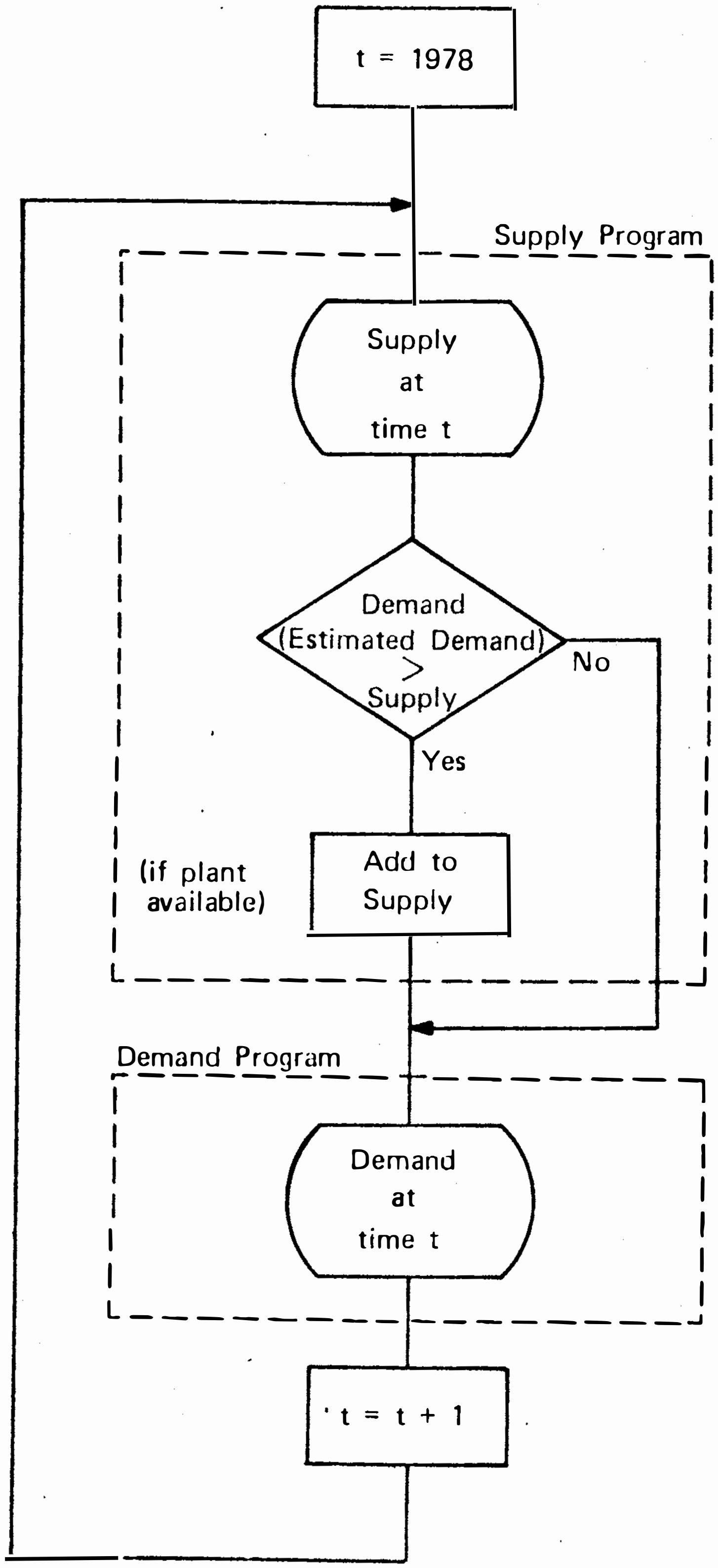
Answers to questions such as these can then be used to determine if supply will be adequate to meet demand for any year between now and 1997. This facilitates evaluation of the impacts of a given supply-demand relationship on the economy of the Pacific Northwest.

1. General Description of the Model. A summary explanation of the modeling process follows. (A detailed explantion of the model is presented in the technical support paper BPA Energy Simulation Model available from BPA's Environmental Manager.) Figure IV-1 shows the flow mechanism of the model and the relationship between supply and demand for electrical energy.

The base year (the year from which all projections are made) is 1977. The supply of electricity from the existing generation system and the resulting cost are determined for 1977 (see Figure IV-2). Demand for electricity in the base year is developed from actual sales data. Demand for 1978, the first year projected, ($t = 1$) is calculated. A comparison is then made to determine if there is equilibrium between supply and expected demand in 1978. If supply were greater than expected demand, the generation system would be judged to have excess supply and additional generation to meet 1978 requirements would not be needed; excess supply would be sold to areas outside the Pacific Northwest. If, on the other hand, demand were to exceed generation supply in 1978, additional generation would be required to place the system back into equilibrium. At this point, the output of the model would indicate the deficiency or excess in the supply and demand relationship for 1978. The same process is repeated for 1979 ($t=2$) to determine at

FIGURE IV-1

MODEL OF PNW ELECTRIC ENERGY SUPPLY AND DEMAND, 1978–1997



what point supply and demand would be in equilibrium. The interative process is continued for each year through 1997 (t = 20), the last year of the planning period. Thus, for each year during the 20-year period, demand and supply levels and costs are developed.

2. Supply. Generation in the supply portion (Figure IV-2) of the model is divided into thermal and hydro, the primary generation sources in the Pacific Northwest. The costs and kilowatthours generated in 1977 from these two sources are the data base for the supply model.

Transmission and distribution cost data for 1977 were taken from BPA's preference utilities' annual financial statements and were used as the base data for those two components of the model. Future additions to transmission and distribution systems were based on planned location of new generation and projected population distribution. The costs per kilowatthour for transmission and distribution for each year between 1978 and 1997 were then calculated in 1977 constant dollars. Generation costs were then combined with transmission and distribution costs. When combined, the three components represent the total cost of the supply system for any given year. The generation, transmission, and distribution costs can be altered to depict several alternative scenarios.

The final cost component is a rate of return or profit margin which is added to the cost of the other three components to determine a supply price for each of the three types of organizations (preference utilities, investor-owned utilities and BPA) which supply energy. The supply price is then inserted into the demand portion of the model, and the supply of energy in kilowatthours in year t = 1 is inserted into the general model (Figure IV-3). Thus, for any given year between 1978 and 1997, the supply price and projected generation capability for the proposed plan, or alternative plan, will be an output of the supply model.

3. Demand. Demand, as used in this context, refers to the term in standard economic reference and not in the context in which the term is used in the electrical energy industry. Any change in population growth and distribution, tastes, incomes and the price of substitute goods, as well as the price of electricity itself, alters the nature and level of the quantity of electricity desired by the ultimate consumer. This quantity is termed "demand." Demand (Figure IV-3) is the most critical portion of the model and requires the most extensive data input.

The amount of electricity consumed is a function of price elasticity of demand. Elasticity is measured by the percentage change in quantity demanded of a good or service divided by the percentage change in price. For example, if electric prices (rates) increase by 30 percent but demand for electricity decreases

Figure IV-2

MODEL DIAGRAM, ELECTRIC ENERGY SUPPLY

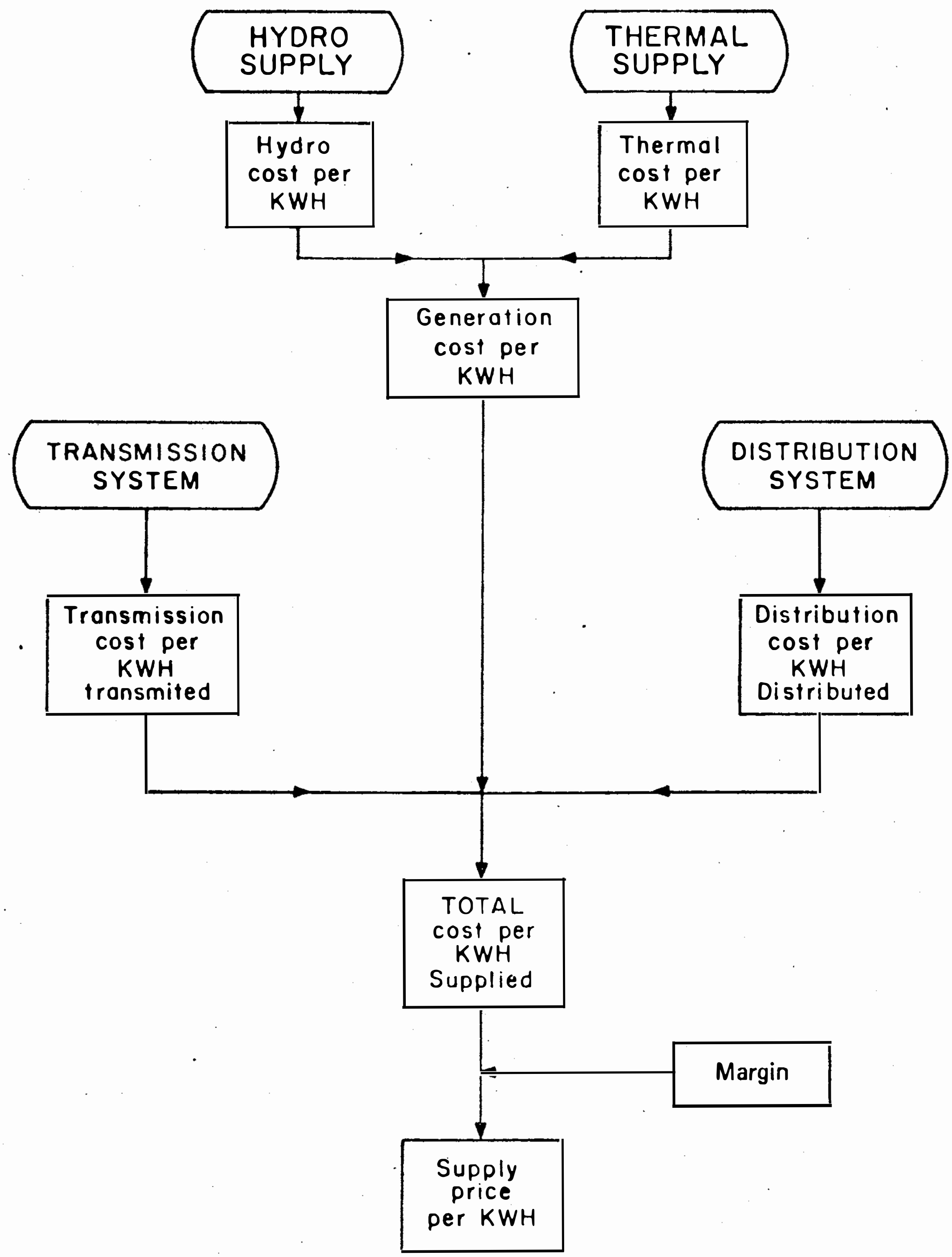
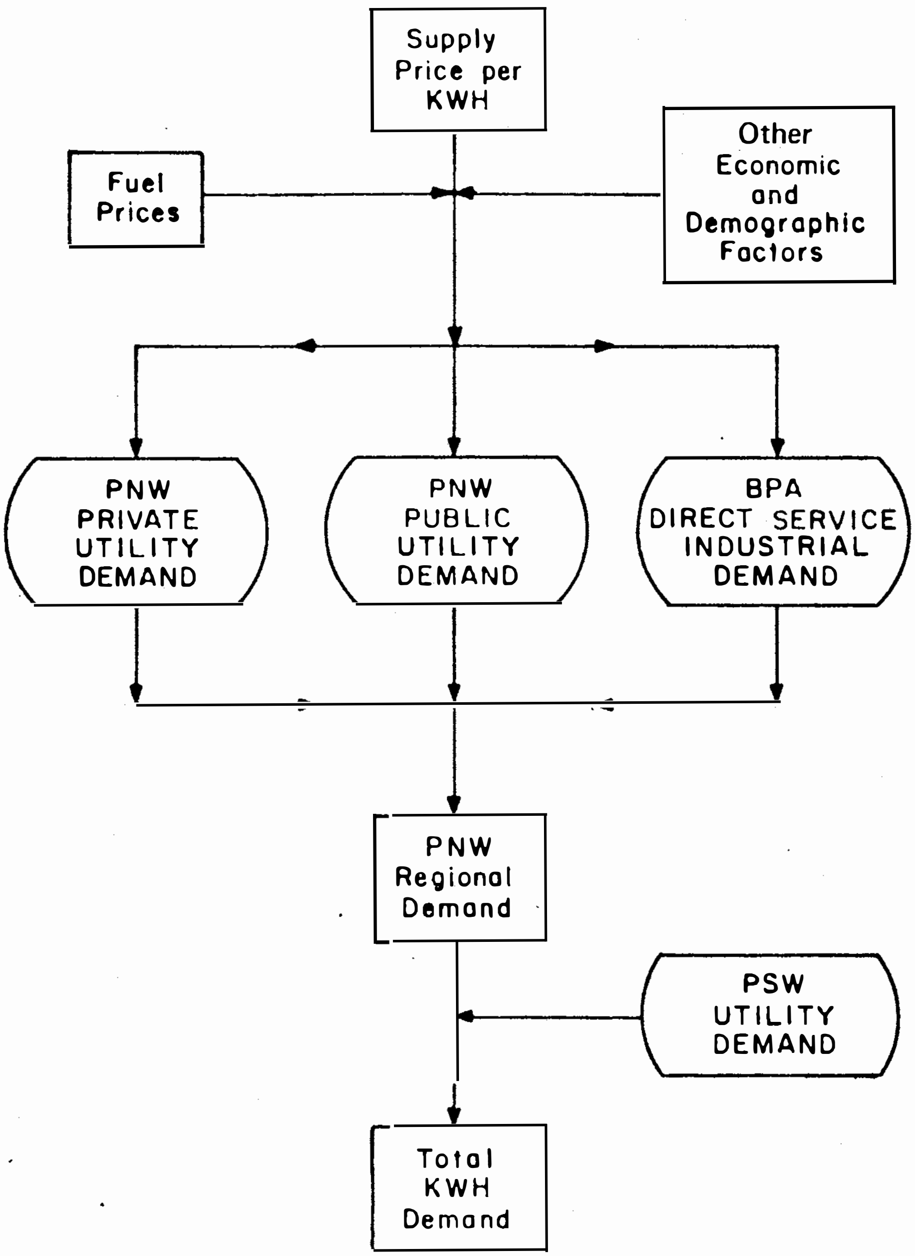


Figure IV–3

MODEL DIAGRAM, ELECTRIC ENERGY DEMAND*



* Demand, as used in this context, refers to the term in standard economic reference and not in the context in which the term is used in the electrical energy industry. Demand, for purposes of this section, refers to the effects price has on quantity demanded in the short-run and in shifts in the nature of demand over time due to changes in demography, tastes, and incomes.

by only 5 percent in reaction to the price increase, then demand is said to be relatively inelastic. In that case, large price increases would not cause consumers to reduce their consumption significantly.

Cross-elasticity and income elasticity have effects on quantities consumed and are included as variables in the demand model. Cross-elasticity measures the effect of changes in the price of substitute goods or services on the quantity consumed of the good or service under consideration. Income elasticity measures effects of income changes on the quantity consumed of a good or service.

The demand model is designed to project sales of electricity to the ultimate consumer for the Pacific Northwest states out to the year 1997. Input data for determining demand include projections of economic and demographic growth, and prices of electricity and other competing energy sources. Although the model contains a set of assumptions regarding economic growth, those assumptions can be modified to reflect alternative scenarios of future economic activity.

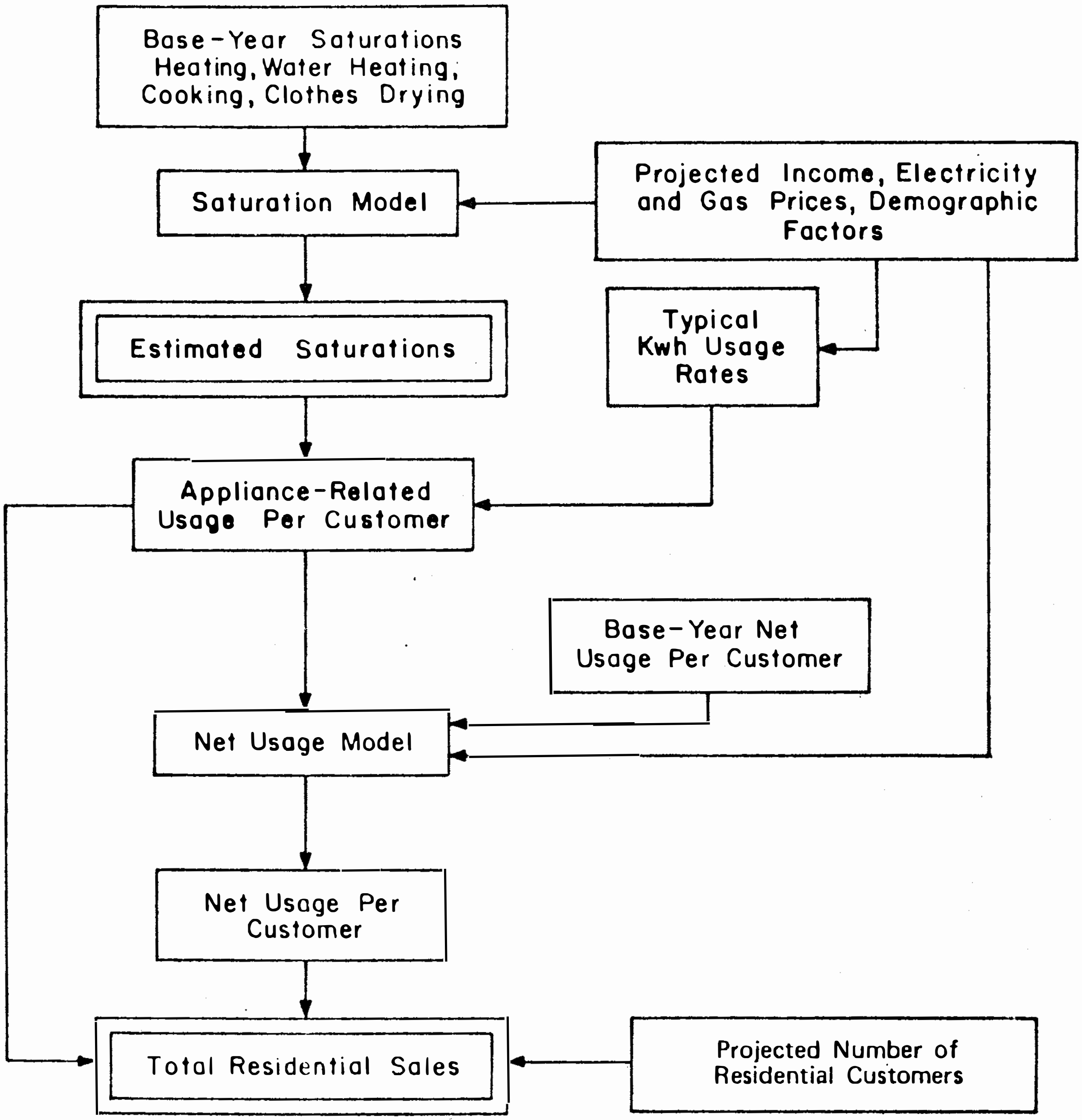
The basic structure for the demand portion of the economic model is a demand model developed by National Economic Research Associates (NERA), commissioned by the Pacific Northwest Utilities Conference Committee (Anderson, 1976). Some of the input data for measuring residential, commercial, and industrial electricity consumption are also from NERA. Additional data on the industrial and commercial sectors, with emphasis on aluminum producers, were developed from a consultant's study commissioned by BPA (Ernst & Ernst, 1976a).

The interaction of electricity and other fuel prices, in addition to other economic and demographic factors, determines the demand for each of the sectors of the economy (residential, commercial, and industrial) which are inputs to the simulation model. The process by which consumption for each of these sectors is determined is visually depicted in figures IV-4 through IV-6 and is described in further detail in Bonneville's publication, <u>BPA Energy Simulation Model</u>, 1977. Together, these economic sectors comprise total Pacific Northwest regional demand (i.e., total demand for both the private and public utilities as well as for the direct-service industrial (DSI) customers of BPA). Once Pacific Southwest utility demand is included, total demand for Pacific Northwest power is known. The demand for electricity in any given year can then be used to determine the demand for alternative fuels (e.g. gas and oil) in that same year.

B. <u>Effects of Revenue Level Alternatives on Regional Energy Consumption</u>. Each of the alternative revenue levels discussed in Chapter III would have a different effect on regional consumption of electricity, gas, and oil. Estimates of these effects have been developed through use of a modified version of the BPA energy

Figure IV–4

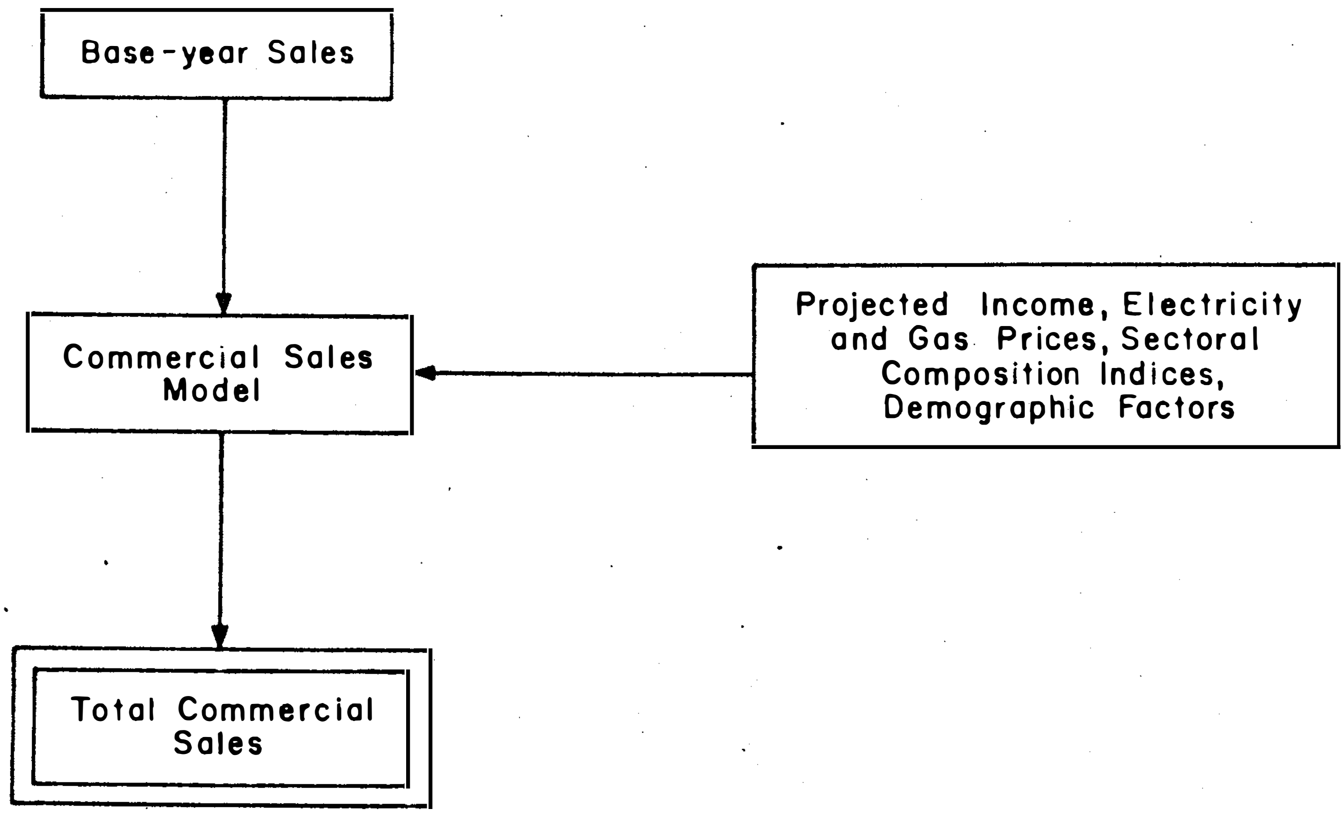
MODEL DIAGRAM, RESIDENTIAL SECTOR



Source: Anderson, 1976, P. 3

Figure IV-5

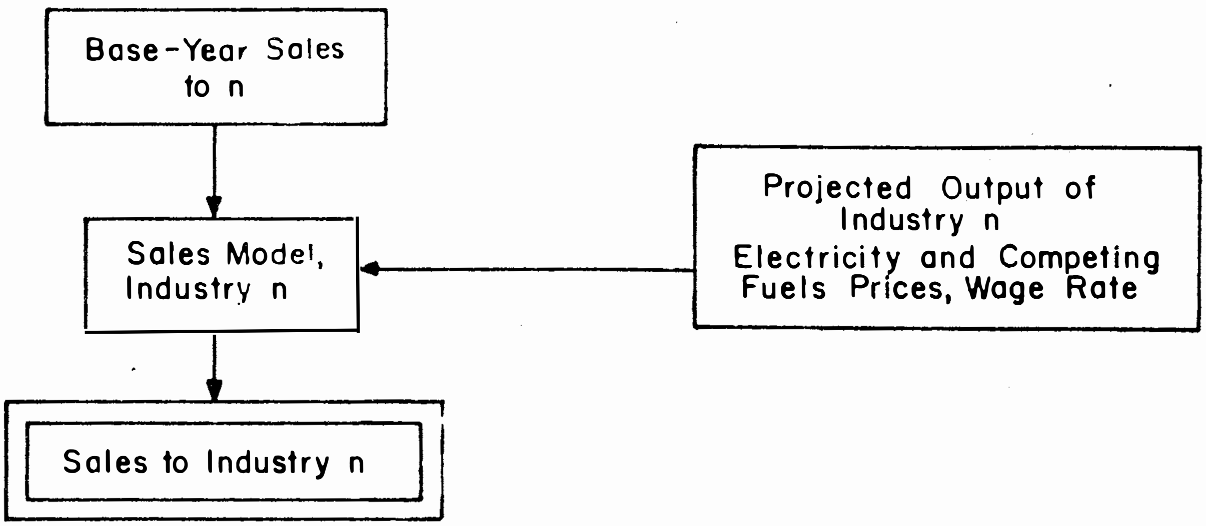
MODEL DIAGRAM, COMMERCIAL SECTOR



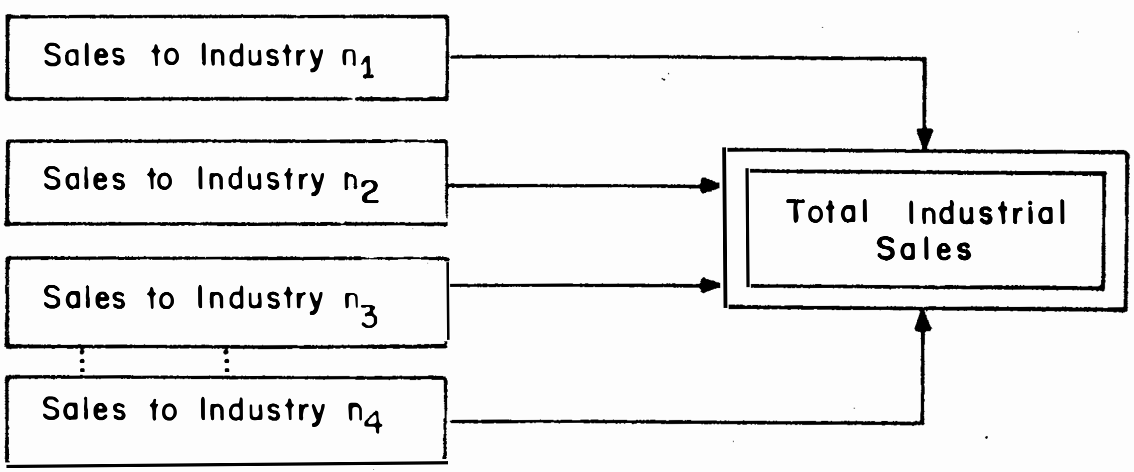
Source: Anderson, 1976, P. 4

Figure IV-6

MODEL DIAGRAM, MANUFACTURING INDUSTRY n



TOTAL MANUFACTURING SECTOR



Source: Anderson, 1976, P. 5

simulation model discussed in the preceding section. Normally the model would develop an electricity price estimate based on an interaction between supply costs and quantity of electricity demanded. In order to isolate the effect of BPA's revenue level alternatives on quantity demanded, however, that portion of the model dealing with the supply price from BPA was altered to reflect the average cost per kilowatthour of power provided by Bonneville under each of the revenue alternatives.

The effects which the revenue alternatives would have on consumption are primarily twofold. First, as cost increases, consumers would be expected to reduce their use of electricity somewhat by refraining from engaging in energy consuming activities. The second response which consumers may make involves substituting another type of fuel, such as oil and gas, for electricity. This response may reduce the demand for electricity, but will not alter the overall demand for energy.

Another type of response to electricity prices could occur among industrial customers. This response is termed a locational effect. An industry may be either attracted to or discouraged from locating in the Northwest as a result of the price of electricity in the region. This effect would probably be significant only for industries for which electricity purchases represent a substantial portion of their production costs.

Each of these responses - conservation, substitution, and industrial location - will have an effect on regional power consumption. The extent of these effects will depend on price elasticity of demand or price sensitivity. Since customer classes vary in price sensitivity, the effects of an electricity price increase will differ somewhat from one class to another. Also, the proportion of change in consumption due to conservation as opposed to fuel substitution will differ across customer groups. We shall now turn to a consideration of the results obtained from BPA's econometric model and how these results may be related to the processes of conservation, fuel substitution, and industrial relocation.

1. Results of BPA's Model.

Table IV-1 shows the consumption levels predicted by the model for the year 1997 for the residential, commercial and industrial sectors of the Pacific Northwest economy under the alternative revenue levels discussed in Chapter III. Because fuel oil and natural gas are most frequently substituted for electricity in the Pacific Northwest, it is important to examine the forecasted consumption of all three fuels under each revenue alternative. It is assumed in the model that BPA's rate increase will be passed along uniformly to all retail customers. Table IV-2 presents the same information as Table IV-1, but all units are converted into trillions of BTU. Table IV-3 is designed to give the reader a better idea of the changes in consumption that will occur under

Table IV - 1
EFFECTS OF REVENUE ALTERNATIVES ON REGIONAL
ENERGY DEMAND - WEST GROUP AREA, 1997

Revenue Alternatives (Precent Increase over Revenue Generated by Existing Rates)[1/]

	0%	40%	83%	90%	195%	895%
Electric Energy Consumption (million kWh)						
Residential	78,922	78,540	77,667	77,537	75,746	64,995
Commercial	61,977	61,731	61,132	61,033	59,892	52,837
Industrial[2/]	111,118	110,679	109,677	109,519	107,686	97,979
Total	252,017	250,950	248,476	248,089	243,324	215,811
Natural Gas Consumption (thousand therms)						
Residential	685,936	690,478	701,460	703,119	729,208	1,025,640
Commercial	494,798	496,330	500,266	501,043	508,731	559,307
Industrial	952,467	954,771	959,871	960,761	970,123	1,013,316
Total	2,133,201	2,141,579	2,161,597	2,164,923	2,208,062	2,598,263
Fuel Oil Consumption (million gallons)						
Residential	436,499	439,261	445,697	446,556	462,479	646,158
Commercial	94,934	95,398	96,489	96,679	98,867	114,590
Industrial	724,679	726,432	730,312	730,990	738,112	770,976
Total	1,256,112	1,261,091	1,272,498	1,274,222	1,299,458	1,531,724

1/ These percentages are based on the revenue alternatives discussed in Chapter III.

2/ Pending the development and adoption of an allocation formula, BPA has not determined if it will serve the loads of its direct-service industrial customers (DSIs) after their existing contracts expire. This analysis assumes that BPA will continue to sell power directly to the DSIs.

Source: Based on Hoffard, et. al., 1977

TABLE IV-2

BTU Equivalents for Electricity, Gas, and Oil Consumption
West Group Area, 1997 1/

(Based on Table IV-1)

	Revenue Alternatives (Percent Increase Over Revenue Generated By Existing Rates					
	0%	30%	83%	90%	195%	895%
Electricity: (Trillion BTU)						
Residential	269,358	268,055	265,075	264,631	258,519	221,828
Commercial	211,526	210,686	208,642	208,304	204,410	180,333
Industrial	379,242	377,744	374,324	373,785	367,529	334,402
Total	860,126	856,485	848,041	846,720	830,458	736,563
Gas: (Trillion BTU)						
Residential	685,936	690,478	701,460	703,119	729,208	1,025,640
Commercial	494,798	496,330	500,266	501,043	508,731	559,307
Industrial	952,467	954,771	959,871	960,761	970,123	1,013,316
Total	2,133,201	2,141,579	2,161,597	2,164,923	2,208,062	2,598,263
Oil: (Trillion BTU)						
Residential	59,364	59,739	60,615	60,732	62,897	87,877
Commercial	13,670	13,737	13,894	13,921	14,237	16,501
Industrial	104,354	104,606	105,165	105,263	106,288	111,021
Total	177,388	178,082	179,674	179,916	183,422	215,399

1/ The following conversion factors were used to generate this table: 1 kwh = 3413 BTU, 1 therm = 10^4 BTU, 1 gallon (residential) = 136,000 BTU, and 1 gallon (commercial/industrial) = 144,000 BTU.

TABLE IV-3
CHANGES IN FUEL CONSUMPTION FOR EACH REVENUE LEVEL
WEST GROUP AREA, 1997

	Revenue Alternatives (Percent Increase over Revenue Generated by Existing Rates)1/					
	0%	30%	83%	90%	195%	895%
Electric Energy Consumption (millions kWh)						
Residential	0	-382	-1,255	-1,385	-3,176	13,927
Commercial	0	-246	-845	-944	-2,085	9,140
Industrial2/	0	-439	-1,441	-1,599	-3,432	13,139
Total	0	-1,067	-3,541	-3,928	-8,693	36,206
Natural Gas Consumption (thousand therms)						
Residential	0	4,542	15,524	17,183	43,272	339,704
Commercial	0	1,532	5,468	6,245	13,933	64,509
Industrial	0	2,304	7,404	8,294	17,656	60,849
Total	0	8,378	28,396	31,722	74,861	465,062
Fuel Oil Consumption (thousand gallons)						
Residential	0	2,762	9,198	10,057	25,980	209,659
Commercial	0	464	1,555	1,742	3,933	19,656
Industrial	0	1,753	5,633	6,311	13,433	46,297
Total	0	4,979	16,386	18,110	43,346	275,612

1/ These percentages are based on the revenue alternatives discussed in Chapter III.

2/ Pending the development and adoption of an allocation formula, BPA has not determined if it will serve the loads of its direct-service industrial customers (DSIs) after their existing contracts expire. This analysis assumes that BPA will continue to sell power directly to the DSIs.

Source: Based on Hoffard, et. al., 1977

each revenue alternative. The "no price increase" scenario is taken as a base case and the change in consumption of electricity, fuel oil and gas is calculated from the data in Table IV-1. Table IV-4 presents the same information in BTU's.

Under the "no price increase" scenario, total regional electricity consumption in 1997 is forecast to be 252,017 million kWh. 2,133,201 million therms of natural gas and 1,256,112 million gallons of fuel oil are also projected to be required to meet regional energy needs.1/

Under Bonneville's rate proposal (90 percent revenue alternative), electricity consumption is expected to be 3,928 million kWh less than under the no increase scenario, assuming that all other prices are held constant. Fuel oil consumption would increase by 31,722 million gallons and use of natural gas would increase by 18,110 million therms under BPA's proposal.

Of all the revenue alternatives considered, the marginal cost case (see Chapter III) would have the most pronounced effect on Pacific Northwest energy consumption. Total energy consumption under this scenario would be lower than under any other alternative, because consumers would not only switch to other types of fuel, they would also conserve more. Section 2 of this chapter discusses the "conservation" and "substitution" effects in some detail. If BPA

1/ Bonneville realizes that comparing therms of natural gas (heat value) to gallons of fuel oil (quantity) may appear to be comparing apples and oranges. However, due to the inherent problems in converting either unit to the other, BPA has chosen to retain the comparison as shown. For example, natural gas is generally expressed as a quantity in mcf or thousands of cubic feet. A fairly accurate conversion is 95 cubic feet to one therm. This conversion is dependent, however, on temperature. Often 100 cubic feet/therm is used instead. The heating oil conversion factor (from gallons to BTU) changes with the type of heating oil used. To convert gallons to BTU, assumptions would have to be made concerning the type of oil used. Because of the guesswork involved, BPA chose to leave the results of the model expressed in gallons and therms for this discussion. The results of the model in BTU are presented in Tables IV-2 and IV-4. The assumptions made in the conversion of all units to BTU's are given in the footnotes to Table IV-2.

TABLE IV-4

BTU Change in Fuel Consumption for Each Revenue Level
West Group Area, 1997

(Based on Table IV-3)

	Revenue Alternatives (Percent Increase Over Revenue Generated By Existing Rates)					
	0%	30%	83%	90%	195%	895%
Electricity: (Trillion BTU)						
Residential	0	1,303	4,283	4,727	10,839	-47,530
Commercial	0	840	2,884	3,222	7,116	-31,193
Industrial	0	1,498	4,918	5,457	11,713	-44,840
Total	0	3,641	12,085	13,406	29,668	-123,563
Natural Gas: (Trillion BTU)						
Residential	0	4,542	15,524	17,183	43,272	339,704
Commercial	0	1,532	5,468	6,245	13,933	64,509
Industrial	0	2,304	7,404	8,294	17,656	60,849
Total	0	8,378	28,396	31,722	74,861	465,062
Fuel Oil: (Trillion BTU)						
Residential	0	375	1,251	1,368	3,533	28,513
Commercial	0	67	224	251	567	2,831
Industrial	0	252	811	909	1,934	6,667
Total	0	694	2,286	2,528	6,034	38,011

were to charge marginal cost rates, electricity use in 1997 would be expected to be 36,206 million kWh less the under the base case. Fuel oil consumption would rise to 275,612 million gallons over base case consumption and natural gas use would rise by 465,062 million therms.

The results produced by the model for the other revenue alternatives are also shown in Tables IV-1 through IV-4. The consumption effects of these alternatives fall between those of the base case and marginal cost alternatives and on either side of those stemming from the proposed revenue level alternative.

2. Components of Changes in Consumption. As indicated previously, changes in the demand for electricity may result from conservation, fuel substitution, or industrial locational effects. This section will describe and quantify, where possible, the nature of each of these components.

a. Conservation. Few studies have attempted to determine what proportion of the elasticity response is due to conservation and what proportion is due to substitution. Bonneville, in a study of its 1974 rate increase, determined that 63 percent of the total elasticity response for the residential sector was attributable to the substitution effect and 37 percent to the conservation effect (BPA, 1973, p. A-42). An estimate made by National Economic Research Associates (NERA) substantiates that approximate breakdown (Devine, et. al., 1977, p. 95). Application of this breakdown could be made to the data presented earlier in Table IV-3 to estimate the expected reduction in regional energy consumption by residential customers in kilowatthours (kWh) under each revenue alternative. For example, approximately 5,153 million kWh of the 13,927 million kWh difference in consumption for residential customers under the base case versus marginal cost revenue alternatives would be due to conservation. The balance of the difference would be accounted for by fuel substitution (increases in the use of alternate energy forms). Comparable conservation effects for the 195 percent, 90 percent, 83 percent, and 30 percent increase revenue alternatives would be 1,175 million kWh, 512 million kWh, 464 million kWh, and 395 million kWh, respectively. In each case, the balance of the consumption effect would be attributable to fuel substitution.

There are, of course, many ways in which residential consumers may conserve. One of the most important responses in the residential sector is the addition of more insulation in existing homes. For example, an econometric study has estimated that a 1 percent increase in the price of all energy sources would result in a 3.5 percent increase in the retrofit demand for insulation (Uri and Major, 1978, p. 5). In fact, that study indicates that the demand for retrofit insulation is more responsive to the price of energy than to the price of the insulation itself.

The commercial and industrial sectors are expected to respond to higher electricity prices by investing in more energy-efficient equipment and processes. Although these investments would be costly, they should still be less than the increased cost of electricity and would thus help mitigate the effects of a rate increase (Chern, 1975, p. 41).

It is well established that an increase in rates would promote conservation as a result of the price elasticity effect, but there is a significant controversy over how far to go in relying on prices to promote the optimum level of conservation. Economists are nearly unanimous in their belief that marginal cost pricing is necessary to provide consumers with accurate price signals in order to provide for the most efficient allocation of society's scarce resources (e.g., Sharefkin, 1974). As the noted economist and regulator Alfred Kahn said, "a failure to get the price of electricity up to marginal cost levels will, therefore, discourage economically sound investments in these energy-conserving devices and practices, and result in uneconomic consumption of energy. And this, of course, is the fundamental case for marginal cost pricing in the first place" (1978, p. 24).

In practice, utilities have been constrained from adopting full marginal cost rates because they would result in the unlawful receipt of excess revenues above the allowable rate of return or cost repayment schedules. As a result, several other rate forms have been promoted to serve conservation purposes (see Chapter VI for a discussion of rate design effects).

b. Substitution. As indicated above, certain portions of the difference in electricity consumption under each of the revenue alternatives would be due to replacement of electrical energy with other forms of energy, primarily fuel oil and natural gas. Solar, wind, geothermal, tidal, and low head hydro energy as well as industrial cogeneration would be additional substitutes for conventionally generated electrical energy. In this section, the effect of a BPA rate increase on the use of these alternative sources is discussed. In the case of conventional substitute fuels the effects can be quantified, but in other cases this is not possible. Of course, should the actual relationships between fuel oil, natural gas and electricity prices deviate from those postulated in the model, the consumption and impact figures will vary accordingly. We have assumed for the purposes of this study that fuel oil and natural gas prices will increase by approximately 4.3[1/] percent each year. (PNUCC, 1979)

1/ This figure is the growth in real dollars; i.e., inflation must be added to this number to get the actual price in a given year.

(1) Fuel Oil and Natural Gas. Oil and natural gas are the most common replacement sources of energy for electricity. Thus, it is expected that oil and gas use would be most affected by an increase in electricity price. In the residential and commercial sectors, most of the increased oil and gas consumed would be used for space and water heating, with small amounts being applied to cooking and clothes drying. In the industrial sector, increased amounts of oil and gas would be used for process heat and space heat.

Table IV-1 on page IV-12 listed the levels of fuel oil and natural gas consumption which could be expected in 1997 with no BPA revenue increase in 1979, or a 30, 83, 90, 195 or 895 percent revenue increase. Changes in gas and oil requirements from the base case were indicated in Table IV-3. The marginal cost alternative would stimulate the largest increase in consumption of gas and oil. Under that alternative, oil consumption would be 275,612 millions barrels (or 22 percent) greater than under the base case. Gas consumption would be 465,062 million therms (22 percent) higher than under the base case. Correspondingly lesser differences would exist for the other revenue alternatives.

(2) Solar Energy. Bonneville is actively involved in solar research and is currently engaged in a residential solar water heating pilot program in order to promote the use of solar energy in the Pacific Northwest and to measure the extent to which solar energy can displace electric energy for residential water heating in this region. The extent to which solar energy will be used to replace conventionally generated power as a result of an increase in electricity rates cannot be quantified to the same extent as the effects on oil and natural gas use. There is, however, a growing amount of research on how electricity rate levels and structures may affect the rate of adoption of sunlight as an energy source.

Just as with natural gas and oil, any increase in electricity rates will enhance the relative economic attractiveness of solar power as a primary energy source, particularly for water and space heating. The rate of adoption of solar energy devices depends on a number of other factors, such as climate, amount of solar radiation, cost of the solar devices, maintenance costs, costs of back-up energy systems, and costs of substitute fuels. As the price of electricity increases, energy consumers will evaluate how that may affect the benefits of switching to some other energy source. It is probable that some energy consumers may elect to install solar devices as a result of an increase in electric rates. However, such an occurrence is likely to be relatively insignificant, based upon recent study done for the Northwest Energy Policy Project which concluded that a doubling of energy prices (100 percent retail price increase) would make the profitability of solar heating systems only marginal at best (Environmental Research Center, 1977, p. x). Of course, if the 895 percent revenue alternative were adopted, retail prices could easily rise by over 400 percent and solar energy would be more attractive from an economic point of view. The economic attractiveness of solar energy is also influenced by rate structure (see Chapter VI, Section C.2.).

(3) Wind, Geothermal, Tidal and Low Head Hydro Power. As is true with solar power, the attractiveness of these alternative energy sources will depend, in large part, on the cost of conventionally generated electricity. As the price of electricity approaches marginal cost, more individuals and utilities will seriously examine alternative sources. Wind power has the drawback of being fairly unreliable in many areas, but BPA is conducting a pilot program utilizing wind power in the Klickitat County Area of the State of Washington. Geothermal power is already in use in Klamath Falls, heating the area's homes. Tidal power has not yet been harnessed in the Northwest; but, given the proximity of the Pacific Ocean, it could be utilized in the future. Use of low head hydro depends, at least in part, on the environmental consequences of building numerous small dams.

(4) Industrial Cogeneration. Many large businesses have steam and heating requirements in addition to electric power requirements. As the price of electricity increases, it may become economical for large commercial and industrial customers to invest in their own power generation. There is a large potential nationwide for cogeneration; Dow Chemical Company (1975, pp. 6-9) has estimated that by 1985, industry could generate 32.5 percent of its power needs, compared with 14.2 percent in 1974. Bonneville, in conjunction with the Pacific Northwest Regional Commission, contracted with Rocket Research Corporation to assess the potential for cogeneration in the Pacific Northwest. According to this study, the Northwest has industrial cogeneration potential of about 1430 MW of which approximately 425 MW is already available, although it is not necessarily fully utilized. Of the remaining 1000 MW, as much as 600 MW might be economically feasible and, by the year 1990, could be developed by industries which have cogeneration ability.

It is very difficult to determine what the price of electricity would have to be for cogeneration to become economical. As Mitchell, et. al. (1977, pp. 61-65), point out, the break-even electricity price for cogeneration cannot be predicted from past experience because industries have never faced such high prices before. However, a study by Resource Planning Associates (1977, p. 212) concluded that, nationwide, electric rates 15 percent higher than those now paid by large industries would increase the adoption of cogeneration by 1,800 MW by 1985 (about 0.3 percent of estimated total electric output for the U.S. in that year).

As with solar energy, rate design can also affect the economic attractiveness of industrial cogeneration. A discussion of these effects is presented in Chapter VI, Section C.2.

c. Industrial Location. A rise in electricity rates in a single geographic area may affect regional growth if decisions about where to locate new industrial plants are influenced by regional differences in electricity prices. Of course, a general rise in electricity rates in all areas would have no effect on the location of industries, but a single geographic area, such as the Pacific Northwest, could be affected if electricity rates were growing at a significantly faster or slower pace than in other areas. State utility regulators across the country have often been confronted with the charge that certain industries will leave the state when faced with an increase in electricity rates (e.g., Stelzer, 1976, p. 287). However, industries would probably be more likely to undertake an extensive conservation program or develop cogeneration capability than to incur the enormous expense associated with relocating (see Chapter V, Section B.2.).

C. Impacts of the Revenue Alternatives on Load Forecasts and Generation and Transmission Requirements.

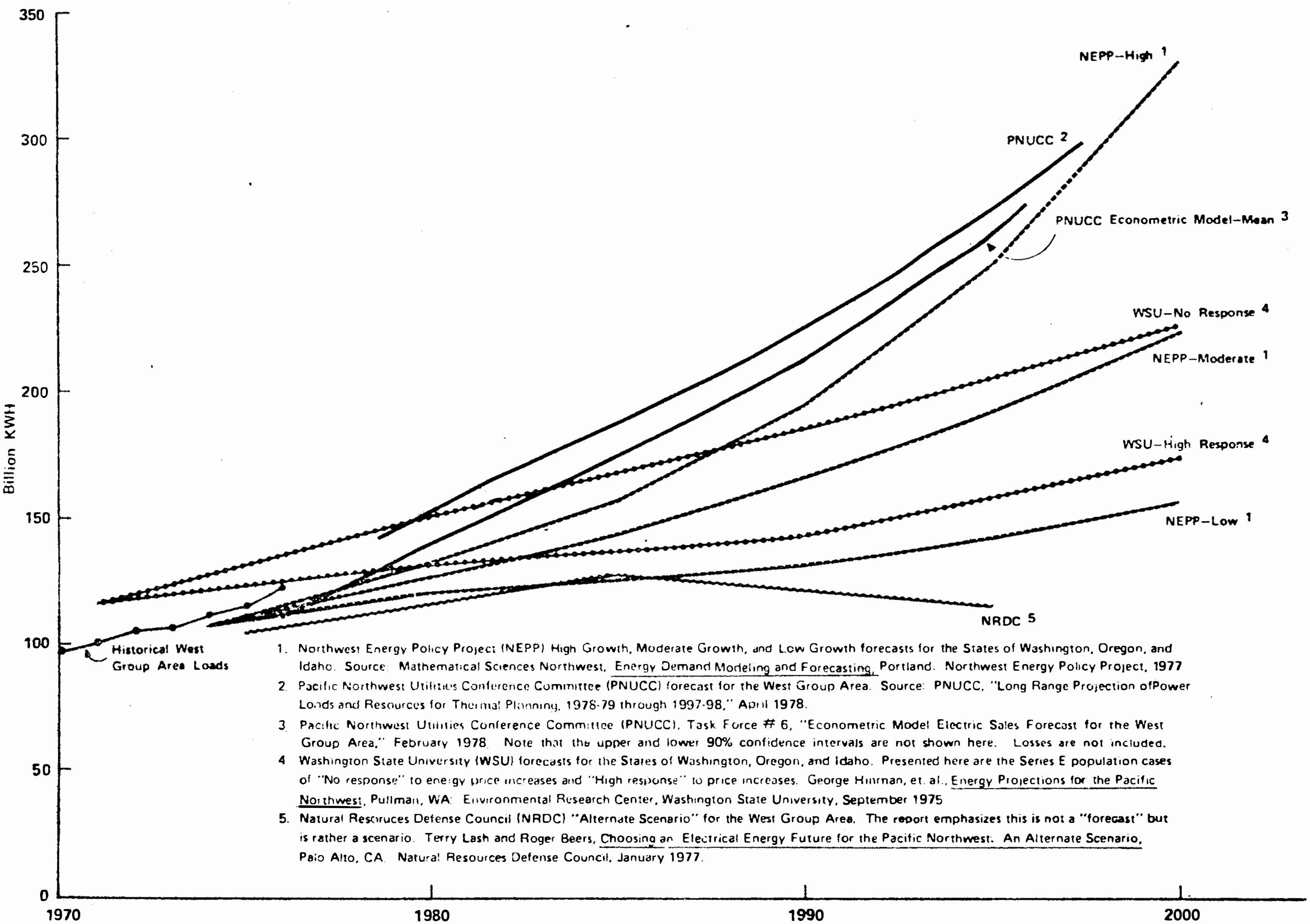
1. Load Forecasts. In the preceding discussion, it has been indicated that the demand for electricity can be expected to change as the real price of electricity changes. In particular, some customers are expected to conserve electricity and/or switch to other energy sources in response to an electricity price increase, and certain industries' decisions about whether or not to locate in the Pacific Northwest may be affected. These considerations are eventually reflected in the Pacific Northwest Utilities Conference Committee's (PNUCC) load forecast, the generally accepted forecast for the region.

In a survey of load forecasting methodologies and assumptions, Ernst & Ernst (1976b) discovered that the forecasting utilities usually did not take into explicit account the effect of the price of electricity on load forecasts; most forecasting utilities considered price indirectly and subjectively via "informed judgment." Thus, it is not possible to assess accurately the consideration forecasting utilities have given BPA's anticipated rate increases in the latest PNUCC West Group forecast. There is, however, evidence that the West Group forecast is not inconsistent with the proposed rate increase.

The econometric model adapted for use by the PNUCC's Task Force 6 (1978) explicitly accounts for electricity price increases, and the mean forecast of that model closely matches the West Group forecast (see Figure IV-7). The econometric model used by BPA for the Role

Figure IV-7

ELECTRICAL ENERGY LOAD FORECASTS FOR THE PACIFIC NORTHWEST



1. Northwest Energy Policy Project (NEPP) High Growth, Moderate Growth, and Low Growth forecasts for the States of Washington, Oregon, and Idaho. Source: Mathematical Sciences Northwest, Energy Demand Modeling and Forecasting, Portland. Northwest Energy Policy Project, 1977
2. Pacific Northwest Utilities Conference Committee (PNUCC) forecast for the West Group Area. Source: PNUCC, "Long Range Projection ofPower Loads and Resources for Thermal Planning, 1978-79 through 1997-98," April 1978.
3. Pacific Northwest Utilities Conference Committee (PNUCC), Task Force # 6, "Econometric Model Electric Sales Forecast for the West Group Area," February 1978. Note that the upper and lower 90% confidence intervals are not shown here. Losses are not included.
4. Washington State University (WSU) forecasts for the States of Washington, Oregon, and Idaho. Presented here are the Series E population cases of "No response" to energy price increases and "High response" to price increases. George Hinman, et. al., Energy Projections for the Pacific Northwest, Pullman, WA: Environmental Research Center, Washington State University, September 1975
5. Natural Resources Defense Council (NRDC) "Alternate Scenario" for the West Group Area. The report emphasizes this is not a "forecast" but is rather a scenario. Terry Lash and Roger Beers, Choosing an Electrical Energy Future for the Pacific Northwest: An Alternate Scenario, Palo Alto, CA. Natural Resources Defense Council, January 1977.

EIS and for parts of this EIS (Hoffard, et. al., 1977) also closely coincides with the West Group forecast. It should be noted that other forecasting models listed on Figure IV-7 use different price projections and different econometric and demographic assumptions, thus resulting in forecasts significantly lower than the West Group Forecast.

It would be expected that the utilities' forecast would be altered if BPA did not increase its rates by approximately 90 percent in 1979. If the rate increase is less than that amount, the forecast would tend to be higher (all other things being equal) while the forecast would tend to be lower if the rate increase exceeded 90 percent. It is not known how the utilities might actually reflect a different rate increase in their load forecasts.

2. Generation and Transmission Requirements. Planning for additional power generation and transmission, of course, follows directly from load forecasting. Although the impacts on the load forecast cannot be estimated precisely, the econometric model provides a general guide to the order of magnitude of impacts on generation and transmission requirements from various BPA revenue increases.

Estimates of the difference between the 1997 base case loads and those under each of the revenue alternatives we have been considering were presented in Table IV-3. Assuming a typical thermal generation plant can produce only 75 percent of the maximum possible energy during the course of a year due to maintenance, refueling, and other outages, 225 to 675 fewer megawatts of generation capacity would be needed with a 90 percent revenue increase. These figures reflect a range of uncertainty of 50 percent, a large, but perhaps not unreasonable, range of uncertainty given the number of variables in the model and the number of years involved.

Implementation of the marginal cost option would produce a lowering of the forecast generation requirement sufficient not only to eliminate the energy deficits which are projected for the 1980's if there were a severe water shortage, but also to allow the operational dates of the publicly-owned generation resources now planned to become operational between 1981 and 1987 to be delayed for varying lengths of time, ranging up to several years. Power plants proposed by investor-owned utilities should not be significantly affected since a BPA rate increase would have minimal impacts on those utilities' costs. It should be noted, however, that these forecasts are extrapolations based on known changes in consumption as a result of a small change in price - the actual change in consumption attributable to a 895 percent rate increase has never been measured. Thus, for this revenue alternative, the model is charting an unknown, but probable course.

D. Impacts of Different Levels of Regional Consumption on the Physical Environment. Figure IV-8 identifies several areas where physical environmental impacts would be a possible result of a BPA wholesale rate increase. Four of these areas may be significant.

1. Impacts of Decreased Generation and Transmission Requirements. Section C of this chapter discussed the effect of different revenue levels on the amount of generation resources needed to meet the demand for electricity in the West Group Area. The particular mix of hydroelectric, coal-fired, nuclear, geothermal, or other types of power plants needed to meet each alternative demand cannot, however, be accurately predicted, since the planning of future electrical resources and other technical, economic, and environmental decisions are totally independent of BPA's rate increase. In addition, the planning period for new generation does not yet extend beyond 1990.

Consequently, it is very difficult to precisely determine the physical environmental impacts likely to be associated with each of the alternative generation requirements. The approach adopted here is to apply the "environmental impact coefficients" developed for use by the Northwest Energy Policy Project to these changes in the demand for electricity (Charles River Associates, 1978, pp. 176-178). These impact coefficients are based upon the expected 1985 generation mix, and they provide a measure of the impacts on the States of Oregon, Idaho and Washington for various categories (e.g., emissions, land use, radiation exposure, occupational injuries) from the generation of a given amount of electricity. The levels of energy consumption (listed in Table IV-1, p. IV-17) in 1997 for the revenue alternatives which have been considered were multiplied by the impact coefficients to derive the impact inventories given in Table IV-5.

The environmental effects in Table IV-5 indicate that unconstrained marginal cost pricing would produce approximately 14 percent less emissions and other impacts from the generation of electricity in the Pacific Northwest than would be the case without a revenue increase. The greatest impact would occur if there were no BPA revenue increase in 1979. The proposed 90 percent increase is expected to have environmental impacts in 1997 approximately 2 percent lower than the impacts without any revenue increase. The figures given in Table IV-5 are based on electrical power use and do not take into account the increased emissions due to switching from electricity to alternate forms of energy (see Table IV-7 for those impacts). These measures provide only a crude indication of the aggregate levels of physical impact.

Figure IV–8

RATE IMPACT ANALYSIS FLOW CHART

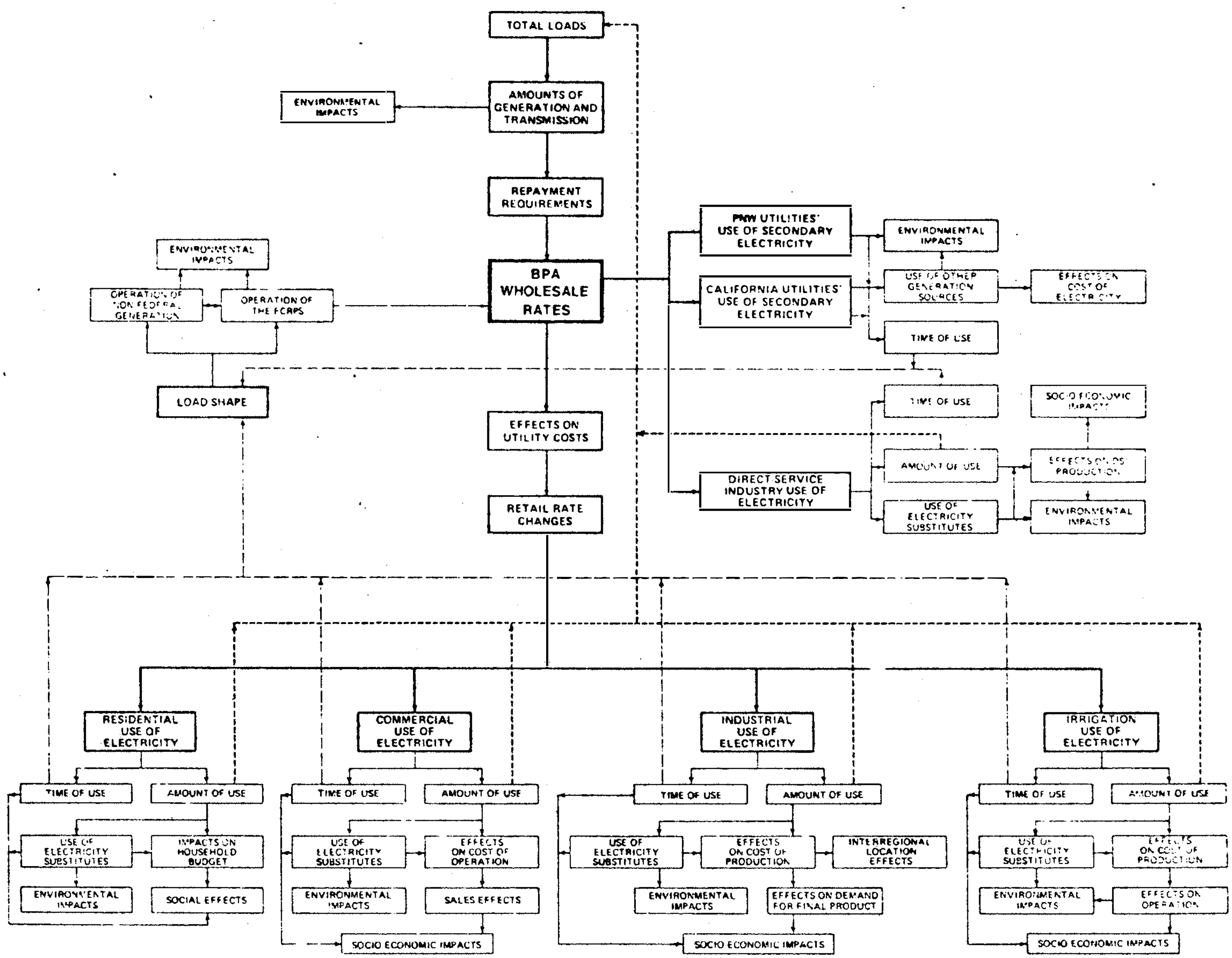


TABLE IV-5
ENVIRONMENTAL IMPACTS FROM ELECTRICAL POWER USE
UNDER BPA RATE OPTIONS
1997 1/

	Revenue Alternatives (Percent Increase Over Revenue Generated By Existing Rates)					
	0 %	30 %	83%	90 %	195 %	895 %
Particulates (Thousand Tons)	34.4	34.3	33.9	33.9	33.2	29.5
Nitrogen Oxides (Thousand Tons)	541.9	539.6	534.3	533.4	523.2	464.0
Sulfur Dioxides (Thousand Tons)	324.3	323.0	319.8	319.3	313.2	277.6
Hydrocarbons (Thousand Tons)	10.7	10.7	10.6	10.6	10.4	9.2
Solid Waste (Thousand Tons)	77,411.3	77,003.7	76,323.7	76,204.8	74,741.2	66,290.7
Land Use (Thousand Acres)	774.1	770.8	763.2	762.1	747.4	662.9
Radiation Exposure (Thousand Man-Rems)	43.9	43.7	43.3	43.2	42.3	37.6
Occupational Injuries (Persons)	507.0	505.0	500.0	500.0	490.0	435.0

1/ Includes impacts occurring only in the States of Washington, Idaho, and Oregon.

Sources: Table IV-1 and Charles River Associates, Integrating Policy Analysis, Portland: Northwest Energy Policy Project, 1978, pp. 176-178.

The impacts shown in Table IV-5 do not provide a measure of the potential for harm to persons (other than occupational injuries), or to flora, or fauna. That potential is not always proportional to the quantity of emissions, because emissions may be more harmful if concentrated near population centers. However, a study by Equitable Environmental Health, Inc. (1976, pp. 294-296) of the cumulative environmental impacts of power generation in the Pacific Northwest through 1995 concluded that under most scenarios the human health impacts are very small. For further information, also see Energy Incorporated, 1977, pp. II-93, 94; and Charles River Associates, 1978, pp. 143-161. Table IV-6 shows the anticipated differences in impact between the base case (zero percent alternative) and each of the revenue alternatives identified in Chapter III.

2. Environmental Impacts From Consumption of Alternate Fuels. To the extent that alternate energy sources such as fuel oil, natural gas, coal, wood, solar, wind, etc., are substituted for electricity as electric rates increase, environmental impacts from consumption of these alternative energy sources will rise. The overall level of air pollution or other environmental impacts may, however, rise, fall, or remain the same as it would be if consumers did not switch fuels, because while one fuel may be as efficient as another, it may also cause more (or less) pollution. However, because conservation occurs as electricity prices rise, the environmental impacts from the use of other fuels do not, even if they are more severe than impacts from electric power generation, overshadow the gains in environmental quality from reduced consumption of all forms of energy use.

a. Impacts from Fuel Oil and Natural Gas Use. Use of oil and natural gas causes atmospheric emissions of carbon monoxide, sulfur oxides, nitrogen oxides, hydrocarbons, particulate matter, carbon dioxide, water, and other materials released or formed during combustion. Additional impacts include potentially increased solid waste disposal and increased impacts from extracting, refining, processing, and transporting these fuels.

Increases in the quantities of fuel oil and natural gas, expected to be used in the West Group Area as of 1997 if BPA were to adopt marginal cost pricing, are shown in Table IV-3. Since marginal cost pricing would result in the highest electric rates and thereby maximize substitution of other fuels for electric energy, this type of pricing would result in the greatest environmental impacts from the use of alternate fuels of any potential rate scenario.

TABLE IV-6
CHANGES IN ENVIRONMENTAL IMPACTS FROM ELECTRIC
POWER USE UNDER BPA RATE OPTIONS
1997 1/

	Revenue Alternatives (Percent Increase Over Revenue Generated By Existing Rates)					
	0 %	30 %	83 %	90 %	195 %	895 %
Particulates (Thousand Tons)	0	- .1	- .5	- .5	- 1.2	- 4.9
Nitrogen Oxides (Thousand Tons)	0	- 2.3	- 7.6	- 8.5	- 18.7	- 77.9
Sulfur Dioxides (Thousand Tons)	0	- 1.3	- 4.5	- 5.0	- 11.1	- 46.7
Hydrocarbons (Thousand Tons)	0	0	- .1	- .1	- .3	- 1.5
Solid Waste (Thousand Tons)	0	- 407.6	- 1,087.6	- 1,206.5	- 2,670.1	-11,120.6
Land Use (Thousand Acres)	0	- 3.3	- 10.9	- 12.0	- 26.7	-111.2
Radiation Exposure (Thousand Man-Rems)	0	- .2	- .6	- .7	- 1.6	- 6.3
Occupational Injuries (Persons)	0	- 2.0	- 7.0	- 7.0	- 17.0	- 72.0

1/ Includes impacts occurring only in the States of Washington, Idaho, and Oregon.

Sources: Table IV-1 and Charles River Associates, Integrating Policy Analysis, Portland: Northwest Energy Policy Project, 1978, pp. 176-178.

Additional residential, commercial, and industrial fuel usage would occur primarily in populated areas where air quality problems are generally more common. Public and municipal utilities would be affected most significantly by BPA rate changes since they rely most completely on BPA power. Therefore, the air quality impacts of BPA rate changes will be felt more severely in urban areas served by public or municipal utilities. Such locations include Seattle, Everett, Tacoma, and Vancouver in Washington, and Eugene in Oregon. Of these, all but Everett currently violate one or more ambient air quality standards.

Table IV-7 estimates the environmental impacts associated with oil and gas use under each BPA revenue alternative. Of course, as electric prices rise and more oil and gas are substituted for electricity the impacts will become more severe. However, because conservation of energy is occurring, the impacts from increased oil and gas use, when combined with the impacts from electric use, diminish as the revenue alternatives rise towards the LRIC (895 percent increase) level.

Table IV-8 presents the changes in the overall levels of impact for each revenue alternative relative to the base case or zero percent level.

Air quality conditions which would result in 1997 independent of BPA rate policies are unknown. If local, State, and Federal air pollution control programs are unsuccessful in attempting to reduce concentrations of ambient pollutants, where violations of air quality standards now occur, increased emissions from increased fuel combustion will be of greater significance and may not even be permitted. The model predicting increases in gas and oil usage for residential, commercial, and industrial purposes assumed no constraints on this usage as a consequence of air quality conditions.

There is some air quality trade-off when direct fuel use is substituted for electric energy. Direct use of oil and gas in lieu of electricity by residential and commercial sectors would generally result in lower absolute quantities of air pollutant emissions in the year 1997 if the generation resources supplying the Pacific Northwest at that time were similar to the expected 1985 mix. Industrial substitution of gas for electricity would also reduce total emissions, but substitution of oil or coal in industrial applications would increase total emissions in the region. Electric applications would increase total emissions in the region. Electric generating plants, however, by the restrictions placed on their operation, design, and siting, would be required to meet air quality standards and "prevention of significant deterioration" regulations. In this respect, air quality

TABLE IV-7
ENVIRONMENTAL IMPACTS FROM OIL AND GAS USE
UNDER BPA RATE OPTIONS
1997 1/

	Revenue Alternatives (Percent Increase Over Revenue Generated By Existing Rates)					
	0 %	30 %	83 %	90 %	195 %	895 %
Particulates (Thousand Tons)	9.8	9.8	9.9	9.9	10.0	11.2
Nitrogen Oxides (Thousand Tons)	375.8	377.2	380.4	380.9	387.7	445.4
Sulfur Dioxides (Thousand Tons)	61.1	61.3	61.7	61.7	62.5	68.2
Hydrocarbons (Thousand Tons)	5.2	5.2	5.3	5.3	5.4	6.3
Solid Waste (Thousand Tons)	0	0	0	0	0	0
Land Use (Thousand Acres)	284.3	285.4	288.1	288.5	294.2	346.0
Radiation Exposure (Thousand Man-Rems)	0	0	0	0	0	0
Occupational Injuries (Persons)	44.0	45.0	45.0	45.0	46.0	54.0

1/ Includes impacts occurring only in the States of Washington, Idaho, and Oregon.

Sources: Table IV-1 and Charles River Associates, Integrating Policy Analysis, Portland: Northwest Energy Policy Project, 1978, pp. 176-178.

TABLE IV-8
CHANGES IN ENVIRONMENTAL IMPACTS FROM OIL AND GAS USE UNDER BPA RATE OPTIONS
1997 1/

	Revenue Alternatives (Percent Increase Over Revenue Generated By Existing Rates)					
	0 %	30 %	83 %	90 %	195 %	895 %
Particulates (Thousand Tons)	0	0	.1	.1	.2	1.4
Nitrogen Oxides (Thousand Tons)	0	1.4	4.6	5.1	11.9	69.6
Sulfur Dioxides (Thousand Tons)	0	.2	.6	.6	1.4	7.1
Hydrocarbons (Thousand Tons)	0	0	.1	.1	.2	1.1
Solid Waste (Thousand Tons)	0	0	0	0	0	0
Land Use (Thousand Acres)	0	2.1	3.8	4.2	9.9	61.7
Radiation Exposure (Thousand Man-Rems)	0	0	0	0	0	0
Occupational Injuries (Persons)	0	1.0	1.0	1.0	2.0	10.0

1/ Includes impacts occurring only in the States of Washington, Idaho, and Oregon.

Sources: Table IV-1 and Charles River Associates, Integrating Policy Analysis, Portland: Northwest Energy Policy Project, 1978, pp. 176-178.

impacts of electric generating plants could be less than impacts of numerous small combustion sources which are not as amenable to regulation and to technological means of limiting emissions and which would often be located in populated areas with existing air quality problems (Charles River Associates, 1978, pp. 175-179; Gordian Associates, 1972, 1974).

b. Impacts from Wood and Coal Consumption. This analysis has not considered additional consumption of wood and coal and other materials as fuels substituted for more expensive, marginally priced electricity since the model is unable to predict such increases. Undoubtedly, some such increases will occur. However, like oil and gas, it is probable that the increase directly attributable to marginal cost pricing would be small. A substantial switch to coal and/or wood could have serious air quality consequences if the switch were to occur in residential usage where air pollution control devices to limit emissions would probably not be applied.

c. Impacts from Increased Reliance on Solar Energy. The environmental impacts of solar energy are expected to be significantly lower than those associated with traditional energy resources. The only anticipated air quality impacts would be secondary impacts from increased production of the materials used in solar devices. There would, of course, be visual impacts as solar collectors are added to the roofs of Pacific Northwest homes. The impacts from increased reliance on solar energy have not been quantified because it is neither known how much solar energy will be used nor is it known how the impacts will change as solar energy becomes a more economically viable alternative energy source.

d. Impacts from Use of Wind, Geothermal, Tidal and Low Head Hydro Energy. From an environmental perspective these sources are not as attractive as solar energy. Wind power requires large windmills to be erected in windy areas (east of the Cascades). These structures will take up a lot of land if they are relied upon to supply much power and they will detract from the natural beauty of the area. Geothermal power will have its primary impact on land use. It is not known what the consequences of large-scale development of this resource might be, but some of the impacts could be similar to those associated with mining. Tidal power would, of course, require that some sort of damming system be built along the coast, in possible violation of Oregon's coastal development plans. Certainly, the facilities would detract from the beauty of the public beaches. The feasibility of low head hyro will probably be site-specific in that the particular area to be flooded will determine the environmental impact. It is doubtful that low head hydropower would significantly contribute to any area recreation resources.

e. Impacts from Reduced Emissions by Ultimate Consumers. Bonneville rate policies may also affect air quality by affecting users of electricity. The decrease in industrial activities as a result of an increase in electricity rates (indicated in Section B.2 of Chapter V) would be associated with a decline in air emissions, but such a beneficial effect cannot be quantified.

3. Impacts from Changes in Irrigation Operations. Water use by irrigators would decrease with an increase in electricity rates, both because of increased water application efficiency and because of a decrease in the number of acres irrigated, although it is not known how much of a decrease can be expected. If such a reduction were to occur it would, of course, leave additional water in the river to allow for other competing uses.

Irrigation from surface sources also contributes to water pollution by reducing the streamflow which, in turn, reduces the dilution and assimilative capacity of the stream. Irrigation runoff also directly increases sediment, mineral, and nutrient loads. The amount of that contribution depends on soil properties, topography, water application rates, irrigation methods, and other factors. Studies have indicated that in the Yakima subregion where gravity irrigation is the norm, the return flows may carry up to 5 times the phosphate, 20 times the sulfate, and 30 times the nitrate concentration of the applied water. The amounts of dissolved solids added to the receiving stream by irrigation have been computed to be 0.24 and 0.325 ton of dissolved solids per year per irrigated acre for the Yakima and Snake River Basins, respectively (Pacific Northwest River Basins Commission, 1971, pp. 14-15). As sprinkler irrigation uses water more efficiently than gravity irrigation, the associated pollution problems are much diminished. Because the primary effect of increased pumping power costs is expected to be on sprinkler irrigation and because comparatively little impact is on gravity irrigation which uses little or no electricity, an increase in electricity costs is apt to do little to reduce irrigation run-off pollution.

It is possible that air pollution in the form of dust emissions could be increased by a reduction in irrigation acreage. Much depends on whether or not the unirrigated land would be dry farmed and also on the soil structure and wind levels in an area. It is, nevertheless, the case that dust emissions are greatly increased by reducing the moisture content of the soil (EPA, 1976, p. 11.2.2-1).

Changes can also be expected in land use since less irrigation development would take place in the event of an increase in electric rates. Whittlesey, et.al., projected significant declines in new irrigation developments in response to large retail electricity price increases, particularly in Southwest Idaho and the Mid-Columbia and Lower Snake regions in Washington (Table IV-9). The new irrigation developments most susceptible to a rate

TABLE IV-9
PROJECTED ACREAGE OF NEW IRRIGATION DEVELOPMENT (1,000 ACRES)
(1977-2020)

Region	Percent Electricity Price Increase1/			
	0	100	200	400
Idaho:				
Southwest	254	154	154	54
South Central	166	126	126	36
Southeast	332	332	220	170
Subtotal	752	612	500	170
Washington:				
Upper Columbia2/	610	610	610	500
Mid-Columbia	248	148	---	---
Lower Snake	112	---	---	---
Yakima	17	17	17	---
Subtotal	987	775	627	500
Oregon:				
Mid-Columbia	260	230	180	20
Willamette	322	322	226	226
All Other	149	89	58	5
Subtotal	731	641	464	251
TOTAL	2,470	2,082	1,591	921

1/ The precent price increase shown below is a retail price increase predicated upon a retail base price of 1.2 cents per kilowatthour.

2/ All land developed in the Upper Columbia is within the Bureau of Reclamation East High Project.

Source: Norman K. Whittlesey, et. al., Demand Response to Increasing Electricity Prices by Pacific Northwest Irrigated Agriculture, Departments of Agricultural Economics, University of Idaho, Oregon State University, and Washington State University, June 1978, p. 44.

increase are those at higher elevations where greater amounts of pumping are required. If land should be taken out of production as a result of BPA's rate increase, it is probable that it will be used for other purposes including grazing (pasture) or development (housing, commercial uses). Clearly the impacts of such events depend on the nature of the property and the use to which it is actually put.

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Chapter V
Impacts of Revenue Alternatives on Utilities and Ultimate Consumers

The purpose of this chapter is to provide a comparative analysis of the effects which the revenue alternatives, discussed in Chapter III, would have on utilities and ultimate consumers. The average rates presented in this chapter for the base case (no increase) alternative are based on BPA's current rates and, therefore, reflect the effects of Bonneville's current rate design. The data for the 30, 83, 90, and 195 percent alternatives, however, are based on the assumption that BPA would implement the rate design features which are currently being proposed by Bonneville. The marginal cost (895 percent increase) alternative reflects a rate design based on the marginal cost principle and therefore differs from both the existing and proposed rate designs. A detailed discussion of the effects of rate design features on power customers will be presented in Chapter VI.

Section A of this chapter discusses the impacts of the increase on BPA's preference customers and on the California utilities, which purchase nonfirm energy and firm capacity from BPA. The impacts on the Southwest customers are further discussed in the share-the-savings section (C.4) of Chapter VI. Section B analyzes the probable effects of BPA's rate increase on the retail customers of BPA's preference customers. In Section C, the impacts on BPA's direct-service customers (direct-service industries and Federal agencies) are noted.

A. Impact of Revenue Alternatives on Utilities.

A BPA wholesale rate increase would have its first-order impact on its utility customers' costs of operation. The magnitude of this impact would depend to a large extent on the proportion of the utility's total costs which are devoted to the purchase of power from Bonneville.

1. Effects on BPA's Preference Customers. Although the ultimate impact of any BPA rate increase would be borne primarily by the retail consumer, the preference utilities themselves would be affected in several ways.

a. Rate of Return. It is possible that a BPA rate increase would lower the rate of return which the preference utilities customarily earn on their operations. A rate of return is income above operating expenses used to pay interest expense and achieve an appropriate return. Publicly owned utilities need a return on equity sufficient to assure confidence in the financial integrity of the utility and to attract debt capital when it is needed. If a utility is currently earning a higher (or lower) rate of return than is necessary, the retail rate increase needed to reflect the increased power costs will be less (or greater) than would otherwise be expected. Some of BPA's preference customers have engaged in a "ramping" process; that is, they are already including some of the anticipated cost increase from BPA in their retail rates. As a result, these customers have built up a slight revenue surplus which will be used to delay their next retail rate increase. The preference customers that have not ramped and have held back on raising their retail rates until BPA's rates become a known quantity will probably need an immediate and sizeable increase in their revenues to offset their increased power costs. Retail customers of utilities which have "ramped" will not notice much of an impact on their power bill when all of BPA's costs are reflected, because they have been paying higher rates in anticipation of BPA's new rates for some time. Other retail customers have enjoyed lower power rates because their utilities reflected only current costs in their rates, but these same customers will now be jolted as their utilities rewrite their rate schedules to reflect their increased power costs.

b. Retail Rate Structure. As a result of BPA's rate increase some utilities may choose to modify their retail rate structures. A discussion of BPA's authority vis-a-vis retail rates is found in Section B.1.c, page V-39. A strong consumer movement might cause the utility to consider raising commercial and industrial rates more than residential rates. On the other hand, a utility might perform a cost-of-service study only to find that residential customers are being subsidized by the industrial sector. Consequently, at least in that case, the residential rate might be increased more than the industrial rate. No matter how the utility chooses to spread a rate increase among its customer classes, at least certain customers at the retail level would be affected. The analysis of the economic and social impacts resulting from a rate increase are presented in Section B of this chapter.

c. Customer Attitude. Even though the public may be developing an awareness of the causes of rapidly rising electric rates, acceptance of increased rates is understandably low. Implementation of effective conservation programs or development of lifeline or baseline rates1/ by utilities may help to reduce opposition. Generally the customers of the investor-owned utilities have complained most vociferously about power rates; however, BPA's rate increase may result in a dramatic increase in retail residential rates of BPA's preference customers and thereby cause residential consumers served by these utilities to also become upset with their utility and the power industry at large.

1/ Lifeline rates are rates which are generally only offered at the retail level to special groups of residential customers, such as the poor or elderly. Baseline rates, on the other hand, are cost based rates offered to all retail customers within a customer class. These rates may be available at either the wholesale or retail level. Baseline rates are discussed in Chapter VI Section C.7.

d. Wholesale Power Costs. The average wholesale firm power rate to each preference customer under both the existing rate structure and the proposed 90 percent increase is shown in Table V-1. Because rate design affects the average wholesale power rate, the percentage increase to any one utility will not necessarily equal 90 percent. Although rate structure does play an important role in terms of the manner in which costs are distributed among BPA's customers, revenue level is generally far more important. Therefore, while the numbers shown in the tables in this chapter incorporate the rate design changes included in BPA's proposed rates, the major impact of the rates is clearly due to revenue level except, perhaps, for the few utilities which have their own generation (primarily hydro). They will be able to schedule the use of their own power (such that they reduce their requirement from BPA) during peak periods and thus reduce their power costs from BPA because demand charges are applicable only to peak hours. Consequently, the average power cost figures for generating utilities are less reliable than comparable figures for BPA's total requirements customers. For further discussion of this topic see BPA's Summary Rate Design Study, (July 1979).

Table V-2 shows the expected average millage increase in wholesale power rates (1980 figures) which would result for each preference utility under each revenue alternative considered in Chapter III. Again, those figures are based on the presumption that if BPA raises its rates it will also adopt the proposed rate structure. Clearly, if the wholesale rates do not change (zero percent alternative) there would be no increase in average cost. The 90 percent increase (the proposed revenue level) was determined by subtracting the current rate in Table V-1 from the proposed rate shown in that table. The 30 percent, 83 percent and 195 percent increases were determined by a proration process; that is, using the 30 percent case as an example, the increase was calculated to be 30/90 of the increase under the 90 percent alternative. Because Bonneville has conducted a marginal cost study (895 percent revenue alternative) and developed a rate which reflects marginal costs, this rate was used to determine the average millage increase under the 895 percent alternative. The average rate under any revenue alternative can be determined by adding the millage increase shown in Table V-2 to the current rate which is given in Table V-1.

Purchased power cost is, however, only a portion of a utility's total expenses. Table V-3 shows the percent of each utility's total costs dedicated to the purchase of BPA power in 1977. In the case of utilities which provide some of their own generation, power costs associated with their own generation are excluded from purchased power costs, but are

Table V-1

AVERAGE CURRENT & PROPOSED RATES IN MILLS/KWH
FOR ESTIMATED LOADS IN CALENDAR YEAR 1980

CUSTOMER NAME	CURRENT RATE	PROPOSED RATE
Municipalities		
Albion	4.11	7.39
Bandon	4.31	7.65
Blaine	4.12	7.44
Bonners Ferry	3.98	7.30
Burley	3.78	7.11
Canby	4.46	7.83
Cascade Locks	4.06	7.45
Centralia	3.78	7.51
Cheney	4.16	7.49
Consolidated ID	3.95	7.35
Coulee Dam	4.06	7.37
Declo	4.15	7.35
Drain	4.27	7.60
Eatonville	4.18	7.45
Ellensburg	4.06	7.31
Eugene	3.73	6.84
Fircrest	4.23	7.54
Forest Grove	3.59	6.89
Heyburn	4.14	7.36
Idaho Falls	4.06	7.31
McCleary	4.26	7.55
McMinnville	3.98	7.47
Milton	4.08	7.33
Milton-Freewater	3.57	6.79
Minidoka	4.29	7.56
Monmouth	4.39	7.86
Port Angeles	3.74	6.87
Richland	4.15	7.57
Rupert	4.05	7.29
Seattle	2.92	5.55
Springfield	3.82	7.10
Steilacoom	4.29	7.58
Sumas	4.37	7.68
Tacoma	2.92	5.72
Vera Irrigation Dist.	4.10	7.42
PUDs		
Benton Co. PUD = 1	3.95	7.34
Central Lincoln PUD	3.91	7.15
Chelan Co. PUD = 1	2.90	5.25

Clallam Co. PUD = 1	4.39	7.71
Clark Co. PUD	3.82	7.12
Clatskanie PUD	3.53	6.59
Cowlitz Co. PUD = 1	3.27	6.27
Douglas Co. PUD = 1	2.91	6.19
Ferry Co. PUD = 1	4.09	7.31
Franklin Co. PUD = 1	3.92	7.12
Grant Co. PUD =2	3.10	5.99
Grays Harbor PUD	3.70	7.08
Kittitas Co. PUD =1	3.83	7.01
Klickitat Co. PUD = 1	3.62	6.78
Lewis Co. PUD =1	3.77	7.06
Mason Co. PUD =1	4.25	7.61
Mason Co. PUD =3	4.20	7.51
Northern Wasco PUD	4.24	7.73
Okanogan Co. PUD =1	3.74	6.98
Pacific Co. PUD =2	4.21	7.51
Skamania Co. PUD =1	4.23	7.55
Snohomish Co. PUD = 1	3.76	7.11
Tillamook PUD	4.23	7.58
Wahkiakum Co. PUD = 1	4.26	7.65
Whatcom Co. PUD =1	3.32	6.51

Cooperatives

Alder Mutual	4.40	7.77
Benton REA	4.07	7.41
Big Bend Elec. Coop	3.72	6.85
Blachly-Lane Coop.	4.05	7.49
Central Elec. Coop.	3.94	7.13
Clearwater Power Coop.	4.25	7.59
Columbia Basin Coop.	3.56	7.02
Columbia Power Coop.	4.00	7.85
Columbia REA	3.60	6.94
Consumers Power	4.25	7.59
Coos-Curry Elec. Coop.	4.11	7.68
Douglas Elec. Coop.	4.25	7.86
East End Mutual	4.21	7.49
Elmhurst Mutual	4.14	7.44
Fall River Coop.	3.87	7.01
Farmers Electric Co.	4.21	7.51
Flathead Elec. Coop.	3.94	7.15
Glacier Elec. Coop.	3.59	6.68
Harney Elec. Coop.	3.61	6.90
Hood River Coop.	4.11	7.33
Idaho Co. L+P Coop.	4.19	7.52
Inland Power + Light	4.06	7.48
Kootenai Elec. Coop.	4.15	7.47
Lakeview L&P Co.	4.06	7.26
Lane Elec. Coop.	4.22	7.56
Lincoln Elec. Coop. MT.	4.13	7.37
Lincoln Elec. Coop. WA.	3.51	6.62

Lower Valley P+L	4.14	7.38
Midstate Elec. Coop.	3.77	6.97
Missoula Elec. Coop.	3.94	7.18
Nespelem Elec. Coop.	4.17	7.44
Northern Lights, Inc.	4.26	7.65
Ohop Mutual	4.28	7.57
Okanogan Elec. Coop.	4.33	7.67
Orcas Power & Light	4.47	7.84
Parkland P&L	4.26	7.55
Peninsula Light Co.	4.09	7.28
Prairie Power Coop.	4.02	7.09
Raft River Coop.	3.60	6.57
Ravalli Elec. Coop.	4.02	7.42
Riverside Electric	4.17	7.46
Rural Electric Co.	4.16	7.44
Salem Electric	4.05	7.30
Salmon River Coop.	3.29	6.71
South Side Lines	3.90	6.96
Surprise Valley Corp.	3.82	7.36
Tanner Electric	4.36	7.70
Umatilla Elec. Coop.	3.36	6.75
Unity Light + Power	4.13	7.38
Vigilante Elec. Coop.	3.75	7.12
Wasco Elec. Coop.	4.39	7.80
Wells Rural Coop.	3.56	6.64
West Oregon Elec. Coop.	4.19	7.52
Federal Agencies		
Bureau of Mines	4.56	8.01
Energy R&D Admin.	3.42	6.64
Fairchild Air Base	3.63	7.27
USIIS-Flathead	4.09	7.94
USIIS-Wapato	2.93	5.94
US Navy	4.68	8.57
DSIs (Aluminum)		
Alcoa Aluminum	3.19	6.15
Anaconda Aluminum	3.03	6.01
Intalco Aluminum	3.19	6.15
Kaiser Aluminum	3.23	6.20
Martin-Marietta	2.77	5.78
Reynolds Metals	3.19	6.15
DSIs (other)		
Carborundum Co.	3.21	6.19
Crown-Zellerbach	3.22	6.19
Georgia-Pacific	3.27	6.26

Hanna Nickel	3.35	6.37
Oregon Metallurgical	3.25	6.23
Pacific Carbide	3.29	6.28
Pennwalt	3.22	6.19
Silicon-Magnesium	3.26	6.24
Stauffer Chemical	3.26	6.24
Union Carbide	3.27	6.25

TABLE V-2

MILLAGE INCREASES UNDER EACH REVENUE ALTERNATIVE

Customer Name	Alternative Revenue Increases 0%	30%	83%	90%	195%	895%
Municipalities						
Albion	0.00	1.09	3.02	3.28	7.11	32.85
Bandon	0.00	1.11	3.08	3.34	7.24	33.64
Blaine	0.00	1.11	3.06	3.32	7.19	32.95
Bonners Ferry	0.00	1.11	3.06	3.32	7.19	32.86
Burley	0.00	1.11	3.07	3.33	7.22	32.60
Canby	0.00	1.12	3.11	3.37	7.30	33.78
Cascade Locks	0.00	1.13	3.13	3.39	7.34	33.35
Centralia	0.00	1.24	3.44	3.73	8.08	33.65
Cheney	0.00	1.11	3.07	3.33	7.22	33.04
Consolidated ID	0.00	1.13	3.14	3.40	7.37	33.41
Coulee Dam	0.00	1.10	3.05	3.31	7.17	32.14
Declo	0.00	1.07	2.95	3.20	6.93	33.15
Drain	0.00	1.11	3.07	3.33	7.21	33.47
Eatonville	0.00	1.09	3.02	3.27	7.08	33.13
Ellensburg	0.00	1.08	3.00	3.25	7.04	32.75
Eugene	0.00	1.04	2.87	3.11	6.74	31.35
Fircrest	0.00	1.10	3.05	3.31	7.17	33.36
Forest Grove	0.00	1.10	3.04	3.30	7.15	30.40
Heyburn	0.00	1.07	2.97	3.22	6.98	33.23
Idaho Falls	0.00	1.08	3.00	3.25	7.04	32.80
McCleary	0.00	1.10	3.03	3.29	7.13	33.40
McMinnville	0.00	1.16	3.22	3.49	7.56	32.66
Milton	0.00	1.08	3.00	3.25	7.04	32.78
Milton-Freewater	0.00	1.07	2.97	3.22	6.98	29.92
Minidoka	0.00	1.09	3.02	3.27	7.09	33.57
Monmouth	0.00	1.16	3.20	3.47	7.52	33.73
Port Angeles	0.00	1.04	2.89	3.13	6.78	31.95
Richland	0.00	1.14	3.15	3.42	7.41	33.57
Rupert	0.00	1.08	2.99	3.24	7.02	32.81
Seattle	0.00	.88	2.43	2.63	5.70	28.73
Springfield	0.00	1.09	3.02	3.28	7.11	32.42
Steilacoom	0.00	1.10	3.03	3.29	7.13	33.33
Sumas	0.00	1.10	3.05	3.31	7.17	33.76
Tacoma	0.00	.93	2.58	2.80	6.07	29.48
Vera Irrigation Dist.	0.00	1.11	3.06	3.32	7.19	32.83

PUDs

Benton Co. PUD = 1	0.00	1.13	3.13	3.39	7.34	33.57
Central Lincoln PUD	0.00	1.08	2.99	3.24	7.02	32.52
Chelan Co. PUD = 1	0.00	.78	2.17	2.35	5.07	27.88
Clallam Co. PUD = 1	0.00	1.11	3.06	3.32	7.19	33.68
Clark Co. PUD = 1	0.00	1.10	3.04	3.30	7.15	32.38
Clatskanie PUD	0.00	1.02	2.82	3.06	6.63	31.42
Cowlitz Co. PUD = 1	0.00	1.00	2.77	3.00	6.50	30.50
Douglas Co. PUD = 1	0.00	1.09	3.02	3.28	7.11	30.69
Ferry Co. PUD = 1	0.00	1.07	2.97	3.22	6.98	33.02
Franklin Co. PUD = 1	0.00	1.07	2.95	3.20	6.93	32.70
Grant Co. PUD = 2	0.00	.96	2.67	2.89	6.26	30.39
Grays Harbor Co. PUD = 1	0.00	1.13	3.12	3.38	7.32	32.49
Kittitas Co. PUD = 1	0.00	1.06	2.93	3.18	6.89	31.91
Klickitat Co. PUD = 1	0.00	1.05	2.91	3.16	6.85	31.78
Lewis Co. PUD = 1	0.00	1.10	3.03	3.29	7.13	32.40
Mason Co. PUD = 1	0.00	1.12	3.10	3.36	7.28	33.40
Mason Co. PUD = 3	0.00	1.10	3.05	3.31	7.17	33.24
Northern Wasco PUD	0.00	1.16	3.22	3.49	7.56	33.83
Okanogan Co. PUD = 1	0.00	1.08	2.99	3.24	7.02	32.09
Pacific Co. PUD = 2	0.00	1.10	3.04	3.30	7.15	33.24
Skamania Co. PUD = 1	0.00	1.11	3.06	3.32	7.19	33.30
Snohomish Co. PUD = 1	0.00	1.12	3.09	3.35	7.26	32.44
Tillamook PUD	0.00	1.12	3.09	3.35	7.26	33.27
Wahkiakum Co. PUD = 1	0.00	1.13	3.13	3.39	7.34	33.41
Whatcom Co. PUD = 1	0.00	1.06	2.94	3.19	6.91	31.41

Cooperatives

Alder Mutual	0.00	1.12	3.11	3.37	7.30	33.94
Benton REA	0.00	1.11	3.08	3.34	7.24	33.52
Big Bend Electric Coop.	0.00	1.04	2.89	3.13	6.78	32.80
Blachly-Lane Coop.	0.00	1.15	3.17	3.44	7.45	33.40
Central Elec. Coop.	0.00	1.06	2.94	3.19	6.91	32.61
Clearwater Power Co.	0.00	1.11	3.08	3.34	7.24	33.55
Columbia Basin Coop.	0.00	1.15	3.19	3.46	7.50	33.01
Columbia Power Coop.	0.00	1.28	3.55	3.85	8.34	35.01
Columbia REA	0.00	1.11	3.08	3.34	7.24	33.65
Consumers Power	0.00	1.11	3.08	3.34	7.24	33.56
Coos-Curry Elec. Co	0.00	1.19	3.29	3.57	7.73	33.86
Douglas Elec. Coop.	0.00	1.20	3.33	3.61	7.82	34.28
East End Mutual	0.00	1.09	3.02	3.28	7.11	33.53
Elmhurst Mutual	0.00	1.10	3.04	3.30	7.15	32.93
Fall River Coop.	0.00	1.05	2.90	3.14	6.80	33.06
Farmers Electric Co.	0.00	1.10	3.04	3.30	7.15	33.20
Flathead Elec. Coop.	0.00	1.07	2.96	3.21	6.95	32.67
Glacier Elec. Coop.	0.00	1.03	2.85	3.09	6.69	31.52
Harney Elec. Coop.	0.00	1.10	3.03	3.29	7.13	33.34
Hood River Coop.	0.00	1.07	2.97	3.22	6.98	32.67

Idaho Co. L+P Coop.	0.00	1.11	3.07	3.33	7.22	33.19
Inland Power + Light	0.00	1.14	3.15	3.42	7.41	33.10
Kootenai Elec. Coop.	0.00	1.11	3.06	3.32	7.19	33.24
Lakeview L&P Co.	0.00	1.07	2.95	3.20	6.93	32.76
Lane Elec. Coop.	0.00	1.11	3.08	3.34	7.24	33.28
Lincoln Elec. Coop. MT	0.00	1.08	2.99	3.24	7.02	32.98
Lincoln Elec. Coop. WA	0.00	1.04	2.87	3.11	6.74	32.36
Lost River Coop.	0.00	1.15	3.19	3.46	7.50	33.33
Lower Valley P+L	0.00	1.08	2.99	3.24	7.02	33.09
Midstate Elec. Coop.	0.00	1.07	2.95	3.20	6.93	32.48
Missoula Elec. Coop.	0.00	1.08	2.99	3.24	7.02	32.58
Nespelem Elec. Coop.	0.00	1.09	3.02	3.27	7.09	33.30
Northern Lights, Inc.	0.00	1.13	3.13	3.39	7.34	33.53
Ohop Mutual	0.00	1.10	3.03	3.29	7.13	33.38
Okanogan Elec. Coop.	0.00	1.11	3.08	3.34	7.24	33.55
Orcas Power & Light	0.00	1.12	3.11	3.37	7.30	33.99
Parkland P&L	0.00	1.10	3.03	3.29	7.13	33.20
Peninsula Light Co.	0.00	1.06	2.94	3.19	6.91	32.82
Prairie Power Coop.	0.00	1.02	2.83	3.07	6.65	33.98
Raft River Coop.	0.00	.99	2.74	2.97	6.43	32.86
Ravalli Elec. Coop.	0.00	1.13	3.14	3.40	7.37	33.30
Riverside Electric	0.00	1.10	3.03	3.29	7.13	33.10
Rural Electric Co.	0.00	1.09	3.02	3.28	7.11	33.31
Salem Electric	0.00	1.08	3.00	3.25	7.04	32.60
Salmon River Coop.	0.00	1.14	3.15	3.42	7.41	32.46
South Side Lines	0.00	1.02	2.82	3.06	6.63	33.10
Surprise Valley Corp.	0.00	1.18	3.26	3.54	7.67	33.71
Tanner Electric	0.00	1.11	3.08	3.34	7.24	33.61
Umatilla Elec. Coop.	0.00	1.13	3.13	3.39	7.34	32.74
Unity Light + Power	0.00	1.08	3.00	3.25	7.04	33.15
Vigilante Elec. Coop.	0.00	1.12	3.11	3.37	7.30	33.33
Wasco Elec. Coop.	0.00	1.14	3.14	3.41	7.39	34.20
Wells Rural Coop.	0.00	1.03	2.84	3.08	6.67	31.86
West Oregon Elec.	0.00	1.11	3.07	3.33	7.22	33.12
Federal Agencies						
Bureau of Mines	0.00	1.15	3.18	3.45	7.47	34.15
Energy R&D Admin.	0.00	1.07	2.97	3.22	6.98	31.77
Fairchild Air Base	0.00	1.21	3.36	3.64	7.89	33.28
USIIS-Flathead	0.00	1.28	3.55	3.85	8.34	35.08
USIIS-Wapato	0.00	1.00	2.78	3.01	6.52	31.33
US Navy	0.00	1.30	3.59	3.89	8.43	36.42
DSIs (Aluminum)						
Alcoa Aluminum	0.00	.99	2.73	2.96	6.41	30.39
Anaconda Aluminum	0.00	.99	2.75	2.98	6.46	30.40
Intalco Aluminum	0.00	.99	2.73	2.96	6.41	30.37

Kaiser Aluminum	0.00	.99	2.74	2.97	6.43	30.52
Martin-Marietta	0.00	1.00	2.78	3.01	6.52	30.44
Reynolds Metals	0.00	.99	2.73	2.96	6.41	30.37
DSIs (other)						
Carborundum Co.	0.00	.99	2.75	2.98	6.46	30.47
Crown-Zellerbach	0.00	.99	2.74	2.97	6.43	30.48
Georgia-Pacific	0.00	1.00	2.76	2.99	6.48	30.65
Hanna Nickel	0.00	1.01	2.79	3.02	6.54	30.90
Oregon Metallurgical	0.00	.99	2.75	2.98	6.46	30.56
Pacific Carbide	0.00	1.00	2.76	2.99	6.48	30.69
Pennwalt	0.00	.99	2.74	2.97	6.43	30.48
Silicon-Magnesium	0.00	.99	2.75	2.98	6.46	30.60
Stauffer Chemical	0.00	.99	2.75	2.98	6.46	30.59
Union Carbide	0.00	.99	2.75	2.98	6.46	30.62

TABLE V-3

PERCENT OF UTILITY COSTS USED IN PURCHASE OF BPA POWER UNDER EACH REVENUE ALTERNATIVE AND IN THE YEAR 1977 (ACTUAL)

Customer	1977 Actual	Alternative Revenue Increases					
		0%	30%	83%	90%	195%	895%
Municipalities							
Bandon	40	38	44	52	52	62	85
Blaine	38	35	40	48	49	59	83
Bonners Ferry	28	38	44	52	53	63	85
Burley	0	29	35	43	44	54	80
Canby	50	54	59	66	67	75	91
Cascade Locks	46	46	52	60	61	71	89
Centralia	29	38	45	54	55	66	86
Cheney	50	50	56	64	65	74	90
Coulee Dam	40	47	53	61	61	71	89
Drain	44	46	51	59	60	69	88
Eatonville	37	35	40	48	49	59	83
Ellensburg	41	44	49	57	58	68	87
Eugene	19	18	22	28	29	39	68
Fircrest	43	42	47	55	56	66	86
Forest Grove	45	12	16	21	21	30	57
Heyburn	53	56	61	68	69	77	92
Idaho Falls	31	30	35	42	43	53	79
McCleary	55	57	62	69	70	78	92
McMinnville	42	28	34	42	43	53	78
Milton	36	34	40	47	48	59	82
Milton-Freewater	14	01	02	02	03	04	11
Monmouth	41	53	59	66	67	75	91
Port Angeles	67	70	75	81	81	87	96
Richland	38	40	46	54	55	65	86
Rupert	39	38	44	52	53	63	85
Seattle	09	06	08	10	11	16	41
Springfield	49	50	56	64	65	74	90
Steilacoom	33	32	37	45	46	56	81
Sumas	30	30	35	42	43	53	79
Tacoma	13	11	14	19	19	27	57
Vera Irrigation Dist.	51	50	56	64	64	73	90
PUD's							
Benton Co. PUD = 1	48	56	62	69	70	78	92
Central Lincoln PUD	48	49	55	63	64	73	90

Chelan Co. PUD = 1	12	06	08	10	11	16	41
Clallam Co. PUD = 1	36	37	42	50	51	61	84
Clark Co. PUD = 1	41	43	49	58	59	69	88
Clatskanie PUD	84	88	90	93	93	95	99
Cowlitz Co. PUD = 1	55	59	66	73	74	81	94
Douglas Co. PUD = 1	26	18	24	31	32	44	72
Ferry Co. PUD = 1	27	27	32	39	40	50	77
Franklin Co. PUD = 1	42	42	48	56	57	67	87
Grant Co. PUD = 2	22	06	08	11	11	17	42
Grays Harbor Co. PUD	33	35	42	50	51	62	84
Kittitas Co. PUD = 1	19	25	30	37	38	48	75
Klickitat Co. PUD =	34	47	53	61	62	72	90
Lewis Co. PUD = 1	49	51	58	66	66	75	91
Mason Co. PUD = 1	31	32	38	45	46	56	81
Mason Co. PUD = 3	41	43	49	56	57	67	87
Northern Wasco PUD	36	36	42	50	51	61	83
Okanogan Co. PUD = 1	41	38	44	52	53	63	85
Pacific Co. PUD = 2	42	42	48	56	57	66	87
Skamania Co. PUD = 1	31	37	42	50	51	61	84
Snohomish Co. PUD =	39	39	45	54	55	65	86
Tillamook PUD	38	37	43	51	52	62	84
Wahkiakum Co. PUD =	39	39	45	53	54	64	85
Whatcom Co. PUD = 1	88	87	90	93	93	95	99

Cooperatives

Alder Mutal	32	33	39	46	47	57	81
Benton REA	39	37	42	50	51	62	84
Big Bend Elec. Coop.	42	45	51	59	60	70	89
Blachly-Lane Coop.	39	42	49	57	58	68	87
Central Elec. Coop.	32	28	34	41	42	52	79
Clearwater Power Coop.	29	31	36	43	44	55	80
Columbia Basin Coop.	34	33	40	49	49	61	84
Columbia Power Coop.	29	32	39	47	48	60	82
Columbia REA	43	45	52	60	61	71	89
Consumers Power	26	29	34	41	42	52	78
Coos-Curry Elec. Co	29	28	34	41	42	53	78
Douglas Elec. Coop.	29	28	33	41	42	52	78
East End Mutual	41	41	47	54	55	65	86
Elmhurst Mutual	48	50	56	63	64	73	90
Fall River Coop.	23	30	36	43	44	55	81
Flathead Elec. Coop.	27	28	33	40	41	52	78
Glacier Elec Coop.	40	34	40	48	49	60	84
Harney Elec. Coop.	32	31	37	46	47	58	82
Hood River Coop.	38	35	40	48	49	59	83
Idaho Co. L+P Coop.	27	29	34	42	42	53	79
Inland Power + Light	28	31	37	45	46	56	81
Kootenai Elec. Coop.	32	35	40	48	49	59	83
Lakeview L&P Co.	45	44	50	58	59	68	88
Lane Elec. Coop.	39	43	49	56	57	67	87

Lincoln Elec. Coop. Mt.	28	27	32	39	40	51	77
Lincoln Elec. Coop. Wa.	36	36	42	51	52	62	85
Lost River Coop.	33	27	34	42	43	55	80
Lower Valley P&L	27	28	33	40	41	51	78
Midstate Elec. Coop.	31	36	42	50	51	62	84
Missoula Elec. Coop.	23	25	30	37	38	49	76
Nespelem Elec. Coop.	37	28	33	40	41	51	78
Northern Lights, Inc.	20	27	32	39	40	50	76
Ohop Mutual	32	31	36	44	44	55	80
Okanogan Elec. Coop.	34	40	46	53	54	64	85
Orcas Power & Light	26	31	36	43	44	54	80
Parkland P&L	51	53	58	65	66	75	91
Penninsula Light Co.	33	35	40	48	49	59	83
Prairie Power Coop.	22	30	35	42	43	53	80
Raft River Coop.	41	40	46	54	55	65	87
Ravalli Elec. Coop.	27	29	35	43	43	54	79
Riverside Electric	44	48	54	61	62	71	89
Rural Electric Co.	35	34	40	47	48	58	82
Salem Electric	41	43	49	57	58	68	87
Salmon River Coop.	23	26	33	41	42	54	80
South Side Lines	43	40	46	54	55	65	86
Surprise Valley Coop.	26	23	28	36	37	48	75
Tanner Electric Coop.	25	25	30	36	37	47	75
Umatilla Elec. Coop.	43	53	60	68	69	78	92
Unity Light + Power	41	42	48	56	57	66	87
Vigilante Elec. Coop.	27	26	31	39	40	51	78
Wasco Elec. Coop.	33	33	38	45	46	56	81
Wells Rural Coop.	17	24	29	37	37	48	76
West Oregon Elec. Coop.	25	26	30	37	38	48	75

TABLE NOTES: The "1977 Actual" figures for each utility are shown in the table for comparative purposes, but the results of the "0 percent" case will generally differ from the "1977 Actual" figures due to the following factors:

1. BPA power costs on a per unit (kWh) basis may vary from those in 1977 due to change in the utility's load characteristics.

2. The utility will probably have a greater load than it did in 1977, thereby increasing its power costs.

3. The utility's distribution costs are assumed to grow by 7.15 percent each year. If the effects of the changes in items 1 and 2 are such that the cumulative increase is greater than 7.15 percent per year, then the figure shown for the "0 percent" alternative will be greater than the "1977 Actual." Conversely, if the increase in power costs is less than 7.15 percent per year, the 0 percent figure will be lower than the "1977 Actual."

4. Several utilities with their own generation show significant changes. These differences are caused by changes in the amount of power purchased from BPA.

still included in total costs. Total costs are defined as: total power costs, transmission expense, operation and maintenance (O&M) expenses, administrative and general expenses, interest expense, tax expense, other deductions, depreciation expense, and return on municipal investment. The figures in the table were derived from the utilities' financial statements and Bonneville's Generation and Sales Statistics for 1977. Data were omitted for utilities which have not filed complete financial data with Bonneville. Also shown in Table V-3 is the percent of each utility's total costs which would be required for the purchase of power from Bonneville in 1980 under each of the revenue alternatives. For the purposes of this study it was assumed that all expenses other than for BPA power would increase at an annual rate of 7.15 percent between 1977 and 1980. This was the average inflation rate experienced by BPA's preference customers between 1974 and 1977. The overall average rate was used, rather than the figure for each individual utility, because individual figures tend to be highly volatile. For example, a one-time accounting change could grossly distort the results of this inflation determination. Similarly, a utility may have made extensive additions to its distribution system between 1974 and 1977 and consequently may have incurred a number of expenses which would not be incurred again for a long time. The purpose of Table V-3 is to provide an estimate of the impact of each revenue alternative on each utility's costs in 1980.

2. Impacts on Pacific Southwest Utilities. Depending on the availability of power and the demand for it in the Northwest, BPA may supply a significant amount of nonfirm secondary electricity to California utilities. For example, BPA sales (H-5 nonfirm energy rate) to those utilities accounted for 6 percent of all electricity consumed in the State of California during 1975 (Fullen, et. al., 1976, p. 36). At the other extreme, in 1977 BPA made no secondary energy sales to California. Nonfirm sales to California are subject to Public Law 88-552 which provides that Bonneville must first offer to sell this power to interested Northwest parties. Only when all Northwest markets have been saturated is Bonneville permitted to offer the power to customers outside the region.

When California utilities receive secondary energy from BPA, the most expensive generating units (usually oil-fired plants) are generally cut back. This reduction in generation leads to reduction in consumption of low-sulfur fuel oil, lowers the cost of electricity to California consumers, and reduces atmospheric emissions in California. For a more complete description of these impacts, see Environmental and Socioeconomic Impacts of Sales of Secondary Electrical Energy to California Utilities, Robert B. Fullen et. al., pp 35-42.

The fuel cost of California utilities' most expensive plants ranged from 20-40 mills/kWh in 1975 (Fullen et al, 1976, pp 43-45) and current costs are in the range of 30-40 mills/kWh. As long as rates plus storage and supply costs related to the use of secondary energy are lower than the operating cost of the most expensive generating units used by the California utilities, there should be no reduction in the amount of secondary energy those utilities would be willing to purchase from BPA, and the environmental benefits of oil-fired generation displacement in California should continue.

The primary impact of a BPA rate increase in California is expected to be socioeconomic. Bonneville's revenue forecast study calculates that under average water conditions, total BPA nonfirm sales to California agencies in calendar year 1980 would be approximately 10.6 million megawatthours. If BPA were to charge 20 mills/kWh for that nonfirm energy under a share-the-savings rate, $212 million in revenues would be received from those sales. This compares to the proposal's lowest rate for nonfirm sales of 4.5 mills/kWh, yielding total revenues of $48 million. Of course, these figures may be smaller or larger depending on the amount of water available for hydroelectric generation at Federal dams in the Pacific Northwest. Under existing rates BPA would expect to receive $34 million from sales to California.

The socioeconomic impacts of this maximum $178 ($212 - $34) million difference between the highest possible cost for the 10.6 billion kWh under the proposal and the cost under existing rates can be derived based on a methodology developed by SRI International (Dick, et. al., 1978). Higher electricity prices can be expected to change the quantity of electricity demanded by all classes of customers, and in the manufacturing sector, these higher prices may affect employment. Based on interpolations of data presented by Dick, et. al., (pp. IV-4, V-4, VI-4, VII-4, and A-5), it appears that electricity prices will be approximately 2 to 4 percent higher in the aggregate service areas of California agencies purchasing nonfirm energy from BPA. In the long run, this price increase can be expected to reduce electricity demand by about 1 or 2 percent. Employment could be expected to decrease by a negligible amount, perhaps by 0.1 to 0.3 percent (Dick, et. al., 1978, pp. III-5 to III-10, A-5, and II-3).

B. Impact on Retail Customers of BPA's Preference Customers.

Bonneville's preference customers serve five general customer classes: residential, commercial, industrial, irrigation, and other (a catch-all designation for such customers as municipal services, schools, sales for resale, etc.). The impact of a BPA rate increase on any of these sectors will be indirect, for the manager or board of directors of each of BPA's preference customers would decide how to incorporate the increased cost of power into the utility's rates. The new retail rates could be designed to shield a particular customer class from a rate increase (and thereby raise rates to other classes), or, more likely, the new retail rates could spread the increase uniformly among all customer classes. This analysis will assume that the increase is uniformly distributed. The analysis in this section will consider the probable impacts of BPA's rate increase on the residential, commercial, industrial, and irrigation customer classes served by the preference customers.

1. Effects on Residential Customers. The effect of the BPA rate increase on residential consumers purchasing power from Bonneville's utility customers is indirect. As a utility's costs go up (whether these be power costs or distribution costs) the rates it charges to its customers (residential, commercial, industrial, irrigation, and other) will have to rise to permit the utility to stay in business.

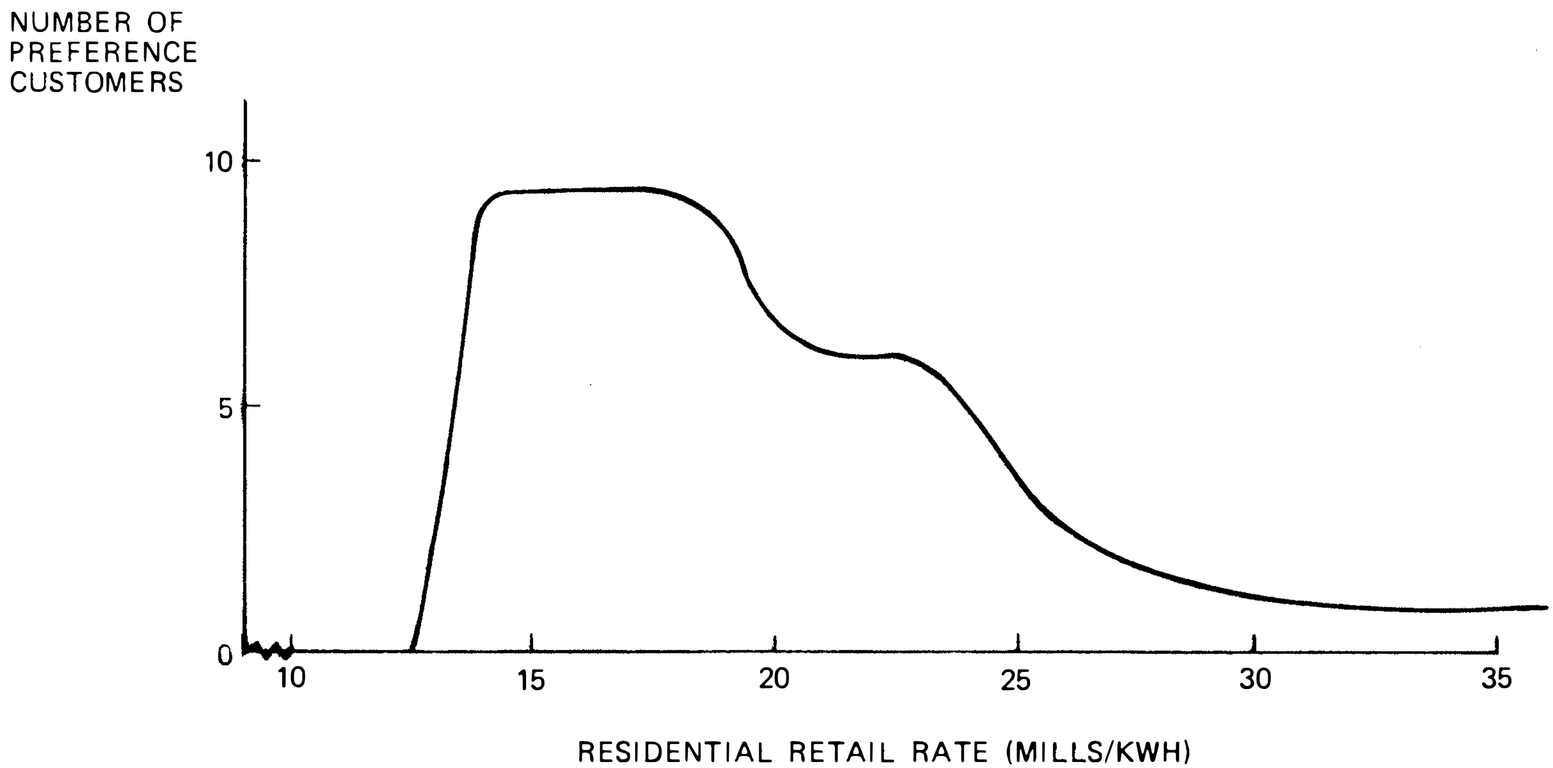
a. Effective Increases to Residential Customers. This section is designed to assist the residential customer in determining what impact a BPA rate increase might have on him, personally. It is probable, however, that Bonneville's rate increase will be responsible for only a portion of any increase which the residential consumer would face, since the retail utility is most probably experiencing a period of rising distribution costs as well as rising power costs.

In an effort to demonstrate the impact of BPA's rate increase, while not overlooking the probable effective increase that a retail customer could face as a result of increased distribution costs, Bonneville has derived Figure V-1, Table V-4 and Table V-5.

Figure V-1 shows the distribution of residential rates (in mills/kWh) which Bonneville expects in 1980. Although individual consumers cannot predict their own retail rate from this graph, the graph does show the range in which a customer might reasonably expect his rate to fall. As an alternatve, the customer could look in Appendix C to find the typical electric bill for his utility. The typical electric bill is calculated for the consumption levels of 500, 1000, and 2000 kWhs per month. A consumer can estimate his average retail rate in mills per kilowatthour as of June 1, 1979, by applying the following formula to the figure for the consumption level most closely resembling his own:

$$\text{Average Retail Rate in mills/kWh} = \frac{\text{Typical bill}}{\text{Corresponding kWh}} \times 1000$$

FIGURE V-1



DISTRIBUTION OF THE PROJECTED AVERAGE RESIDENTIAL RETAIL RATES FOR BPA'S PREFERENCE CUSTOMERS

TABLE V-4

YEARLY EXPENDITURES (DOLLARS) ON ELECTRICITY BY RESIDENTIAL CONSUMERS

Monthly kWh Consumption	Rate in Mills/kWh 5.0	10.0	15.0	20.0	25.0	30.0	35.0	40.0	45.0
100	6.00	12.00	18.00	24.00	30.00	36.00	42.00	48.00	54.00
200	12.00	24.00	36.00	48.00	60.00	72.00	84.00	96.00	108.00
300	18.00	36.00	54.00	72.00	90.00	108.00	126.00	144.00	162.00
400	24.00	48.00	72.00	96.00	120.00	144.00	168.00	192.00	216.00
500	30.00	60.00	90.00	120.00	150.00	180.00	210.00	240.00	270.00
600	36.00	72.00	108.00	144.00	180.00	216.00	252.00	288.00	324.00
700	42.00	84.00	126.00	168.00	210.00	252.00	294.00	336.00	378.00
800	48.00	96.00	144.00	192.00	240.00	288.00	336.00	384.00	432.00
900	54.00	108.00	162.00	216.00	270.00	324.00	378.00	432.00	486.00
1,000	60.00	120.00	180.00	240.00	300.00	360.00	420.00	480.00	540.00
1,250	75.00	150.00	225.00	300.00	375.00	450.00	525.00	600.00	675.00
1,500	90.00	180.00	270.00	360.00	450.00	540.00	630.00	720.00	810.00
1,750	105.00	210.00	315.00	420.00	525.00	630.00	735.00	840.00	945.00
2,000	120.00	240.00	360.00	480.00	600.00	720.00	840.00	960.00	1,080.00
2,250	135.00	270.00	405.00	540.00	675.00	810.00	945.00	1,080.00	1,215.00
2,500	150.00	300.00	450.00	600.00	750.00	900.00	1,050.00	1,200.00	1,350.00

TABLE V-5

YEARLY EXPENDITURES ON ELECTRICITY AS A PERCENT OF ANNUAL NET INCOME

Yearly Expenditures (Dollars)	Annual Net Income (Dollars) 1,000	2,500	5,000	7,500	10,000	12,500	15,000	17,500	20,000	22,500	25,000
50	5.00	2.00	1.00	0.67	0.50	0.40	0.33	0.29	0.25	0.22	0.20
100	10.00	4.00	2.00	1.33	1.00	0.80	0.67	0.57	0.50	0.44	0.40
150	15.00	6.00	3.00	2.00	1.50	1.20	1.00	0.86	0.75	0.67	0.60
200	20.00	8.00	4.00	2.67	2.00	1.60	1.33	1.14	1.00	0.89	0.80
250	25.00	10.00	5.00	3.33	2.50	2.00	1.67	1.43	1.25	1.11	1.00
300	30.00	12.00	6.00	4.00	3.00	2.40	2.00	1.71	1.50	1.33	1.20
350	35.00	14.00	7.00	4.67	3.50	2.80	2.33	2.00	1.75	1.56	1.40
400	40.00	16.00	8.00	5.33	4.00	3.20	2.67	2.29	2.00	1.78	1.60
450	45.00	18.00	9.00	6.00	4.50	3.60	3.00	2.57	2.25	2.00	1.80
500	50.00	20.00	10.00	6.67	5.00	4.00	3.33	2.86	2.50	2.22	2.00
550	55.00	22.00	11.00	7.33	5.50	4.40	3.67	3.14	2.75	2.44	2.20
600	60.00	24.00	12.00	8.00	6.00	4.80	4.00	3.43	3.00	2.67	2.40
650	65.00	26.00	13.00	8.67	6.50	5.20	4.33	3.71	3.25	2.89	2.60
700	70.00	28.00	14.00	9.33	7.00	5.60	4.67	4.00	3.50	3.11	2.80
750	75.00	30.00	15.00	10.00	7.50	6.00	5.00	4.29	3.75	3.33	3.00
800	80.00	32.00	16.00	10.67	8.00	6.40	5.33	4.57	4.00	3.56	3.20
850	85.00	34.00	17.00	11.33	8.50	6.80	5.67	4.86	4.25	3.78	3.40
900	90.00	36.00	18.00	12.00	9.00	7.20	6.00	5.14	4.50	4.00	3.60
950	95.00	38.00	19.00	12.67	9.50	7.60	6.33	5.43	4.75	4.22	3.80
1,000	100.00	40.00	20.00	13.33	10.00	8.00	6.67	5.71	5.00	4.44	4.00
1,050	105.00	42.00	21.00	14.00	10.50	8.40	7.00	6.00	5.25	4.67	4.20
1,100	110.00	44.00	22.00	14.67	11.00	8.80	7.33	6.29	5.50	4.89	4.40
1,150	115.00	46.00	23.00	15.33	11.50	9.20	7.67	6.57	5.75	5.11	4.60
1,200	120.00	48.00	24.00	16.00	12.00	9.60	8.00	6.86	6.00	5.33	4.80

In general, it would be possible for the customer to estimate his new retail rate (after the BPA wholesale power rate increase) by adding the 90 percent millage increase shown in Table V-2 to the rate derived from the typical bill publication. Should the reader wish to test the effects of BPA's adoption of an alternative to the 90 percent proposal, he can substitute any other millage increase from Table V-2 into his calculation. However, because some utilities have engaged in a "ramping" process, that is, they have based their existing rates at least in part on the presumption that Bonneville will raise its rates by 90 percent in December 1979, it may not be appropriate to add the full amount of the millage increase shown in Table V-2 to the typical bill. Utilities which have ramped have been asked by Bonneville to notify their customers of the practice, so readers should know whether or not they will have to make an adjustment.

Tables V-4 and V-5 provide the reader with information designed to assist him in estimating the actual impact of this rate proposal on him, personally. By matching one's probable residential rate (as determined above) with one's monthly average consumption in Table V-4, one can determine yearly expenditures on power. By referencing Table V-5 it is possible to ascertain that proportion of take-home pay (net income) which must be devoted to power purchases on an annual basis. By selecting alternative retail rates and kWh consumption levels, the consumer can compare expected yearly expenditures with current costs and is free to make assumptions about how he might conserve if his retail rate were to increase.

b. Interaction Between Income, Energy Prices, and Consumption. It is impossible to predict how the individual customer will react to the residential rates he will probably face in 1980. Some will conserve by adding insulation to their houses, turning off lights, hanging their clothes out to dry rather than using a "dryer," etc. Others have already taken these measures and may have to cut down on purchases of other goods. Still others may switch to other forms of energy. For example, they may buy a gas furnace to replace their electric heating system or possibly install a solar water heater rather than using their electric model.

Although BPA is in no position to predict individual reactions to price changes, it is possible to discuss the general relationship between income, energy prices, and energy consumption.

Several factors including the size, location, and type of dwelling unit (single family versus multiple family) are important determinants of residential energy costs. For example, the Bureau of Labor Statistics' most recent Consumer Expenditure Survey (1977, p. 359) indicates that, on the average, Western[1]/ consumers living in rental housing spent only 52.5 percent as much on natural gas and electricity as did persons who owned their homes. A much larger proportion of rental housing than of owner-occupied housing consists of multiple family dwellings. In addition to minimizing exterior wall surfaces, multifamily units have fewer occupants per unit, are generally smaller than single family homes, and the incomes of their occupants are, on the average, lower than those of homeowners.

Income level is another important element affecting energy consumption. As indicated in Figure V-2, a direct positive relationship exists between income level and amount of residential energy consumed. As income levels rise, people are able to afford larger homes and a greater variety of energy consuming appliances. Berman, Hammer, and Tihansky (1972, p. 4) indicate that income level and family size are the primary determinants of the number and types of appliances possessed by residential consumers.

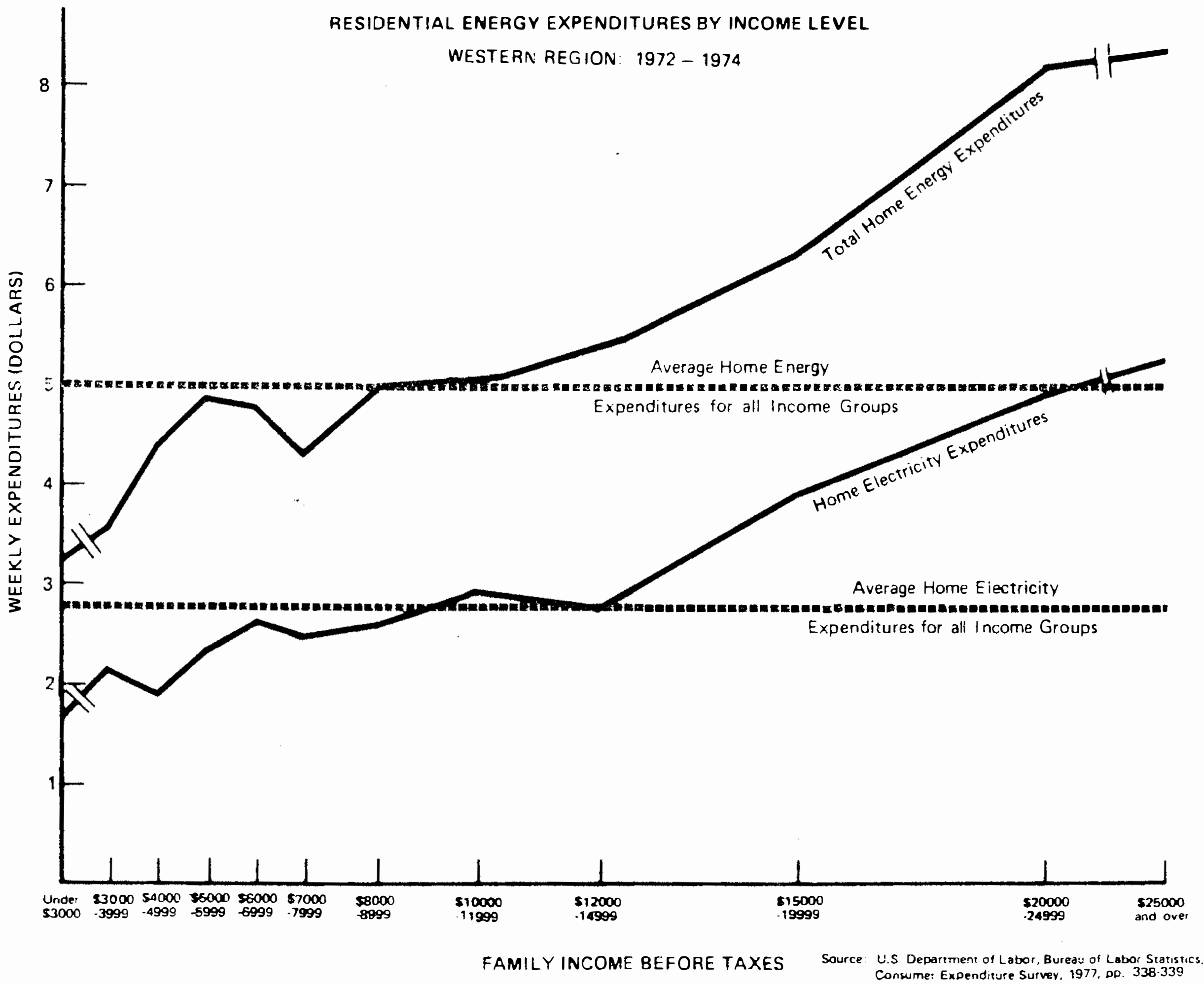
Given the relationship between consumer appliance inventories and family size, the data presented in Figure V-3 are not surprising. As family size increases, residential energy consumption also increases, up to a point.

After family size reaches five, energy consumption declines somewhat. Possibly this downturn could be attributed to the financial strains which can confront larger families, thereby inhibiting their ability to purchase a larger number of appliances.

The type of energy required by the residential customer also plays an important role in the amount of money devoted to energy purchases. The low-income consumer with oil heat is likely to find an increase in his electric bill more burdensome than the gas customer since the former's energy budget is generally already considerably larger than the latter's (FEA, 1975, p. 2.37). Location also affects the price of various types of energy, thereby influencing the proportion of income needed for energy purchases. Electricity prices vary significantly throughout the Pacific Northwest (see Appendix C) and, therefore, the competitiveness with gas and oil will vary throughout the region.

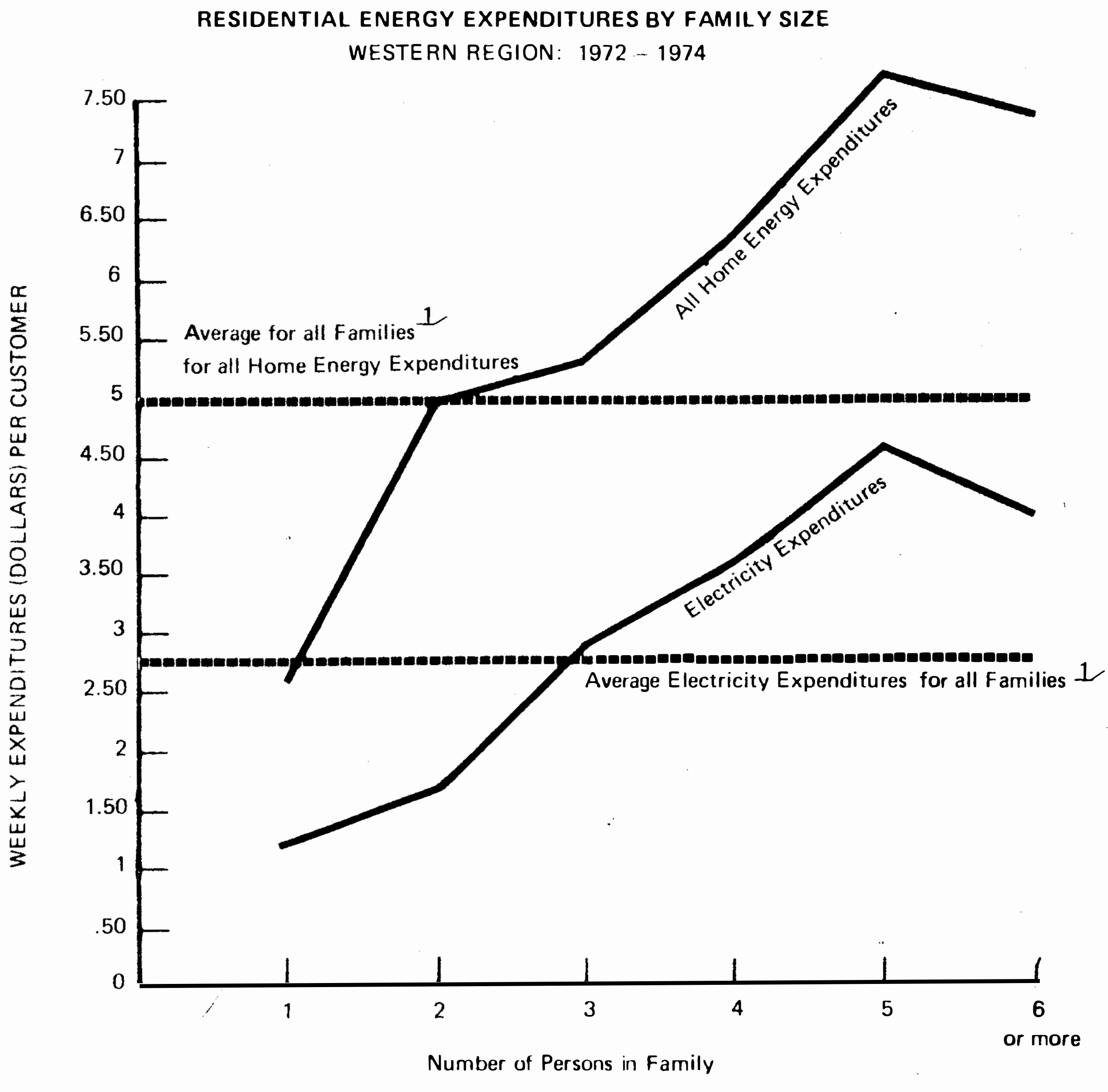
1/ Consists of the following states: Alaska, Arizona, Colorado, California, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

FIGURE V-2



Source: U.S. Department of Labor, Bureau of Labor Statistics, Consumer Expenditure Survey, 1977, pp. 338-339

FIGURE V-3



1/ Includes Individuals Living Alone

Source: U.S. Department of Labor, Bureau of Labor Statistics, Consumer Expenditure Survey, 1977, pp. 340-341

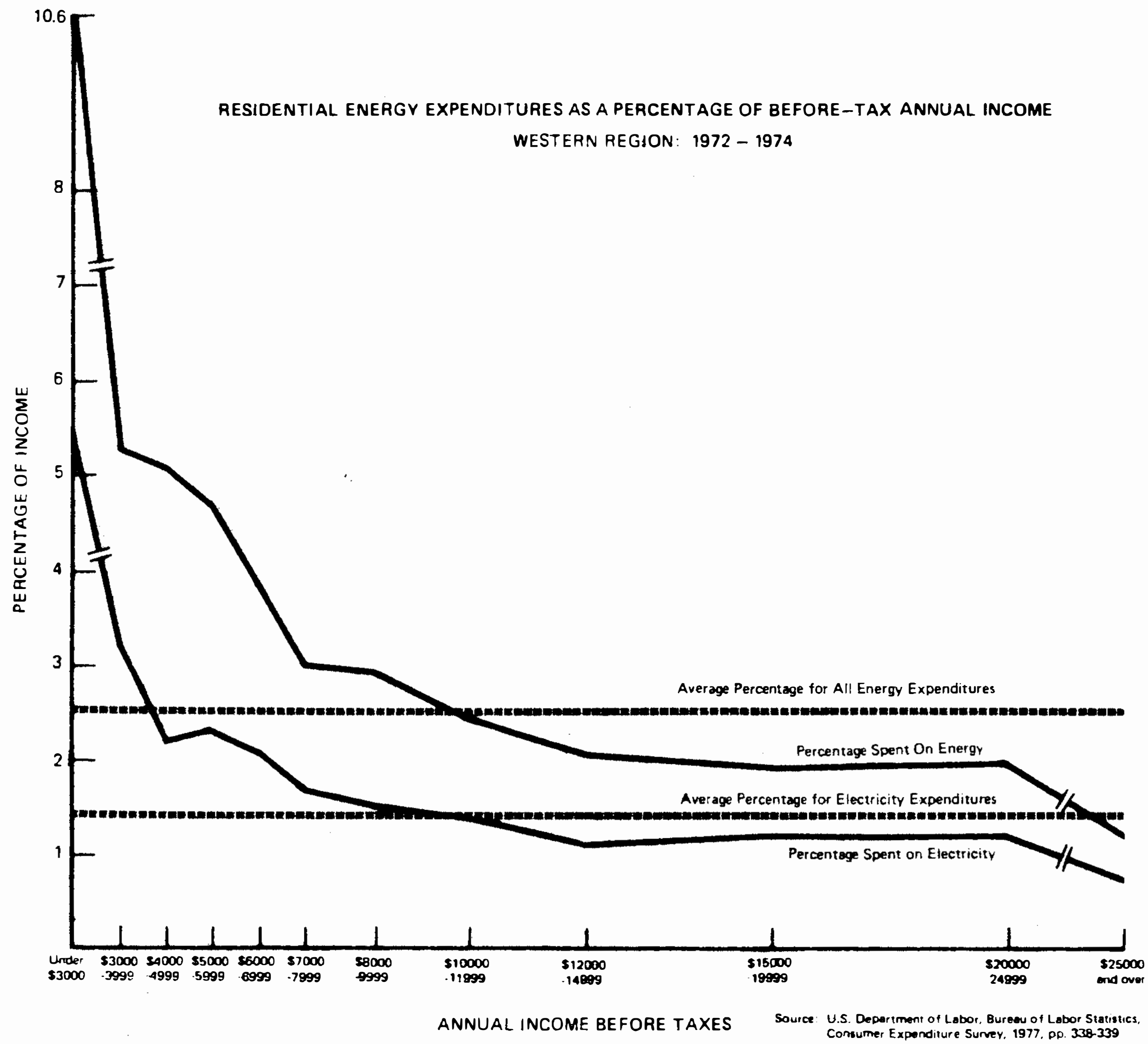
Illustrated in Figure V-4 are the average energy expenditures by customers in various income brackets as a percentage of before-tax income. Clearly, the energy expenditures of particular customers depend on their needs, desires, location, family size, and income level (as well as other factors of somewhat lesser importance such as age, occupation, and education). These factors also influence the proportion of family income which is spent on energy. Unfortunately, the form of the data used to prepare this chart did not permit specification and control of the effects of these factors. Nevertheless, it is evident that, for whatever reasons, the poor must devote a significantly larger share of their before-tax income to energy than the rest of the population. These results are corroborated by analyses done for the Northwest Energy Policy Project (Charles River Associates, 1978, p. 96).

Further complicating the position of the poor is the fact that minimum customer service charges and declining block rates have resulted in higher per-unit costs to many of the poor in comparison with more affluent consumers. A study by the Washington Center for Metropolitan Studies indicates that the poor (37 percent of whom are 65 years of age or older) pay per-unit rates for electricity and natural gas which are, respectively, 56 percent and 82 percent greater than those paid by the non-poor (Newman, 1974, pp. 5-6). Although the recent trend toward flat energy rates (uniform charge per kWh, regardless of usage) should reduce these figures, elimination of customer charges would be even more effective in reducing these high unit costs. By eliminating declining block rates and adopting a flat rate schedule, the utility is ensuring that the rate burden falls primarily on the higher use customers.

As shown in Figure V-4, the percentage of income devoted to energy use in the home ranges from 0.8 percent for families with incomes of $25,000 and over to 10.6 percent for those with incomes of less than $3,000. Among the poor, a significant portion of this expense, more than half on the average, is devoted to purchasing electricity.

Unless steps are taken to mitigate its impact, any increase in the price of electricity will require a proportionately larger share of the resources of low-income groups than of higher income consumers. For example, assuming that consumption would not change as rates go up, an increase in retail electricity rates of 50 percent would raise the percentage of income required for the purchase of electricity by families with incomes under $3,000 from 5.4 percent to 8.1 percent; an increase of 2.7 percentage points. The comparable change for persons in the $25,000 and over bracket would be 0.4 percentage points (from 0.8 to 1.2). In other words, as a percentage of income, the impact on these low-income consumers would be nearly seven times that experienced by those making $25,000 or more.

FIGURE V-4



Source: U.S. Department of Labor, Bureau of Labor Statistics, Consumer Expenditure Survey, 1977, pp. 338-339

Of course, the poor would probably attempt to conserve even more as their rates rise, lessening the financial impact of the rate increase.

Low-income consumers are less able than higher income consumers to transfer expenditures from other budget items to cover increased energy costs since most of their incomes are committed to the purchase of basic necessities such as food, shelter, and clothing. For example, those with incomes of less than $3,000 spent 47 percent of that income on food. Only 8 percent of total gross income was devoted to food purchases by those earning $25,000 and over (Bureau of Labor Statistics, 1977, pp. 332-333). This is despite the fact that those same low-income consumers averaged expenditures of only $14.37 per week for food compared with $56.60 averaged by those with high incomes. Lyman (1978, p. 28) presents empirical evidence that increases in household income result in higher price elasticity. He suggests that "as income rises, a household adjusts its mix of electicity-using durables to include durables providing luxury services or services with luxury features," thereby increasing the household's price sensitivity.

Given that increases in the cost of electricity would represent larger proportional impacts on the incomes of low-income consumers than on those of higher income consumers, it might seem that the former would be more likely to reduce consumption in the face of cost increases. However, research by Berman, Hammer, and Tihansky (1972, p. 19) indicates that a positive relationship exists between ability to reduce electricity consumption and level of income. An explanation of this finding is suggested in a report by Barth, Mills, and Seagrave (1975, pp. II-13 and II-14) in which they show that the poor devote a greater percentage of their energy use to space heating than do "typical families." (See also Charles River Associates, 1978, pp. 92-99.) The poor, having already limited their consumption to basic essentials, would have to experience genuine deprivation to achieve additional reductions in use.1/ Furthermore, as Berman, et. al. point out, high-income groups typically reduce electricity consumption by shifting fuels and replacing inefficient appliances. The poor do not possess the funds required for such adjustments. Attempts to improve home insulation levels are also beyond the means of many lower income families.

1/ This condition has been recognized and to some extent ameliorated by existing social weatherization programs offered to the poor and/or aged by various Federal and State agencies.

We have been referring to "the poor" or "low-income" consumers without actually placing a precise definition on these terms. The primary reason for this is that a concrete definition of poverty simply does not exist. As indicated by Tussing (1975, p.2), "It is common to define poverty as an insufficiency of means relative to needs or as a condition of moneylessness." Still, there may be considerable disagreement over what constitutes need. Tussing points out further that poverty goes beyond simply moneylessness and may be viewed "as an aspect of social pathology that includes not only moneylessness but dependency, helplessness, lack of political influence, and the like." With this in mind, the discussion which follows is based on one commonly employed index of poverty - that developed by the U.S. Social Security Administration. This definition is used by the Census Bureau in its official reports.

In 1964 the Social Security Administration (SSA) developed an estimate of the amount of money required by a family to meet basic needs necessary for a decent standard of living. This amount of money was considered to be the line between the poor and the non-poor. Some revision of this standard was made in 1969 to reflect differences in food costs for farm versus non-farm families. The standard also varies with family size.

The SSA index has been adjusted each year based on changes since 1963 in the Consumer Price Index (CPI). Based on the most recent available CPI index (June, 1979) the current poverty level would be $7185 for a nonfarm family of four. The poverty level for farm families is set at 85 percent of the level for urban families. The most recent estimates (U.S. Bureau of Census, 1978) place the proportion of the population in the Western Region which falls below this poverty line at 10.1 percent.

c. Preference and Priority to Residential Customers. Bonneville has always interpreted its statutory obligations concerning preference and priority to mean that it must serve public utilities and cooperatives before it can meet the needs of private power customers. As the furor over rising prices escalates, more and more people are closely scrutinizing BPA's legislative mandates. The City of Portland launched a campaign to bring lower cost Federal power to its residents by claiming that the main thrust of the Bonneville Project Act was the establishment of preference and priority for domestic and rural consumers, rather than the establishment of preference for a particular type of utility customer. At the present time, however, the Administrator is continuing to give preference to public bodies and cooperatives.

Another type of preference and priority for domestic and rural consumers would be a "rate" preference. Legally Bonneville is permitted to review and approve (or disapprove) a preference customer's retail rates. Although BPA does not have the authority to set them, Bonneville does have the authority, if it determines that the resale rates are inequitable, to terminate the power sales contract. Section 17b of BPA's General Contract Provisions (which apply to all power sales contracts) states:

> If the Purchaser changes its resale rates or the relationship between the rates for various classes of customers, or applies its rates or makes charges for power in a manner inconsistent with or in violation of the provisions of sections 15 and 17 of this exhibit, or if the Purchaser fails to carry out the policy stated in Federal statutes that electric power and energy purchases hereunder shall be sold to ultimate consumers at the lowest possible rate consistent with sound business principles, the Administrator shall have the right to terminate this contract by giving notice of such termination to the Purchaser. Such termination shall become effective upon the expiration of the time thereafter, not exceeding 18 months, which is reasonable required by the Purchaser to obtain electric power and energy from other sources.

Section 5 of the Bonneville Project Act provides the legal foundation for this contract provision by stating:

> Contracts entered into with any utility engaged in the sale of electric energy to the general public shall contain such terms and conditions, including among other things, stipulations concerning resale and resale rates by any such utility, as the administrator may deem necessary, desirable or appropriate to effectuate the purposes of this Act and to insure that resale by such utility to the ultimate consumer shall be at rates which are reasonable and nondiscriminatory.

Termination of the power sales contract is a drastic measure and has never been taken. Rather than wield a legal club, BPA attempts to work with the customer to develop an equitable set of rates.

It has been suggested that Bonneville use its authority to enforce the giving of rate preference to domestic and rural consumers. A baseline rate would be one means of accomplishing this objective. This option is discussed in Chapter VI, Section C.7.

d. Long-Run Consumption Effects Because residential consumers are not "in business" they are unable to pass along any rate increase to their customers. As a result, those users would be most severely affected by a BPA rate increase. Table IV-3, shows the expected actual change in consumption for electricity, oil, and gas under each revenue alternative. Under the proposed rates, the residential sector's electric consumption would be 1,385 million kWh lower in 1997 and use of fuel oil would be 10,057 million gallons higher than it would be without the rate increase. Natural gas use would increase by 17,183 million therms. These figures represent changes from what the expected consumption would be in 1997 if no rate increase were implemented.

2. Effects on Business and Industry. When faced with a significant increase in the cost of electricity or a change in the rate structure, businesses and industries often have a variety of possible courses of action available to them (CERCDC, 1978, p. IV-39):

-"Reduce electric consumption by reducing production (possibly laying off employees) or altering product mix;

-Substitute labor for electricity (possibly increasing employment);

-Substitute capital and/or management for electricity;

-Absorb the costs by reducing profit margin, stockholder benefits, or employee benefits;

-Pass the costs on to consumers through higher prices and/or lower product quality;

-Change energy sources;

-Switch to on-site generation of electricity;

-Switch load to off-peak periods (in case of peak load pricing);

-Expand or branch elsewhere;

-Relocate to lower cost area;

-Cease operations."

Several of these possible impacts are covered elsewhere in this chapter, while this section focuses on the economic impacts of an increase in the price of electricity to industries.

a. The Importance of Electricity Costs in Industrial Location.

There are several indications that the cost of electricity may influence industrial location. Price elasticity studies for the industrial sector which have used national cross-sectional data, have recognized that energy-intensive industries tend to locate in low power cost regions, thus upwardly biasing their elasticity estimates. The proportion of price elasticity which is attributed to this location effect ranges from one-fifth (Halvorsen, 1976, p. 621) up to nine-tenths (Joskow and Baughman, 1976, p. 14). Bonneville's 1973 Impact Study (p. A-23) estimated that one-third of the industrial elasticity was attributable to the location effect. This means that (to use the BPA example) a 1 percent increase in the real price of electricity in a given region will cause a 1 percent decline in industrial electricity use due to conservation and fuel substitution, plus a 0.5 percent decline due to a decrease in industrial location competitive advantage, other things being equal. This loss of regional competitive advantage does not necessarily mean that existing industries would move out of the region, but more probably that fewer energy-intensive industries might choose to locate in this region in the future.

Another way to measure the influence of electricity price on industrial location is to statistically analyze the relationship between the price of electricity and the types of industries in the various regions of the country. Temple, Barker, and Sloane (1976, pp. IV-16 to IV-19) conducted such a study, attempting to discover which industries are "over-represented" in the low power cost regions. They found that six industry groups demonstrated a statistically significant tendency to concentrate in areas where electricity prices are relatively low. The six industries were chemicals; paper products; rubber and plastics; stone, clay, and glass; petroleum products; and lumber products. Wilson (1969, p. 172), in a similar analysis of the Tennessee Valley Authority service area, also concluded that the low rates in that region were "a significant and important determinant of both the rate and pattern of industrial development in the east south-central United States." Wilson found electricity prices to be statistically significant in the following industries: primary metals, paper products, lumber products, food, electrical machinery, and stone, clay and glass products. In the case of chemicals, textiles, machinery, and transportation equipment, Wilson found electricity prices to be insignificant only once, suggesting that these industries, too, are price sensitive. (See also Huntington and Smith, 1977.)

That method of analysis was applied to the Pacific Northwest in BPA's Role Draft EIS (1977, Appendix C, pp. IV-68 to IV-73), and it was found that the results for the above two studies could not be completely substantiated in this region. Although primary metals, paper products, and lumber products are strongly represented in this region, other electricity-intensive industries (e.g., petroleum products; rubber and plastics; and stone, clay, and glass) are not as well represented in the Pacific Northwest as they are in the rest of the country. In addition, paper and lumber are resource-based industries which require the region's raw materials in their products. Without the timber resource, it is unlikely they would concentrate in the Pacific Northwest regardless of electricity prices. Finally, consideration of more specific industry groups would make the analysis significantly more complex.

It is apparent that the role of electricity prices in industrial location is not a simple one. Other important factors, such as labor costs, markets, proximity to raw materials, transportation costs, and so on, also play significant roles in the location of manufacturing. However, an increase in electricity rates in the Pacific Northwest should have only a relatively small influence on the rate of regional industrial growth. A study done for the Northwest Energy Policy Project concluded that although some energy-intensive industries could be significantly affected, even under "worst case" assumptions the region's employment would be reduced by less than 1 percent with higher energy prices (Charles River Associates, 1978, p. 119). Studies in other areas also support the conclusion that higher electricity prices would have a long-run employment effect of less than 1 percent (Bohm and Eblen, 1974; Ontario Hydro, 1976, Vol. XB, p. 34; and CERCDC, 1978, p. IV-39). The locational effects would be felt over a very long time; for example, Baughman and Zerhoot (1975, p. 19) believe it takes 26 years to achieve 90 percent of the locational effect.

b. The Relative Importance of Electricity in Production Costs.

One key to determining the potential impacts on business and industry is the price elasticity of demand for electricity of commercial and industrial customers.

Several studies have estimated the price elasticity for several industrial categories (Table V-8). Although the estimates vary widely for individual industries, the ordinal ranking among all industries is fairly consistent. The five most price-responsive industries appear to be chemicals; stone, clay, and glass; primary metals; pulp and paper; and textiles. A comparison with Figure V-4 indicates that industries which consume larger quantities of electricity are usually the same industries which are more responsive to price increases (as Wilson, 1969, p. 113, pointed out). Chern (1975, p. 42) has concluded that the ability to substitute natural gas for electricity is the most important determinant of industrial electricity price elasticity.

Another method of measuring the potential effect that electric rate increases might have on industry is to examine electricity expenditures as a proportion of value added (value added is a measure of the market price of goods produced minus the cost of materials purchased from others). Table V-7 presents that proportion from an input-output study of Oregon, Washington, and Idaho industry in 1972. It reveals that the primary metals (aluminum, other non-ferrous metals, and iron and steel) are the most electricity-intensive industries, followed by mining, chemicals, and pulp and paper. In all the other industrial sectors, electricity purchases account for less than 3.0 percent of value added. Several other studies (Ernst & Ernst, 1976, p. III-16; Nissel, 1976, p. 22: Wilson, 1974, p. 420-422; and

Table V-6

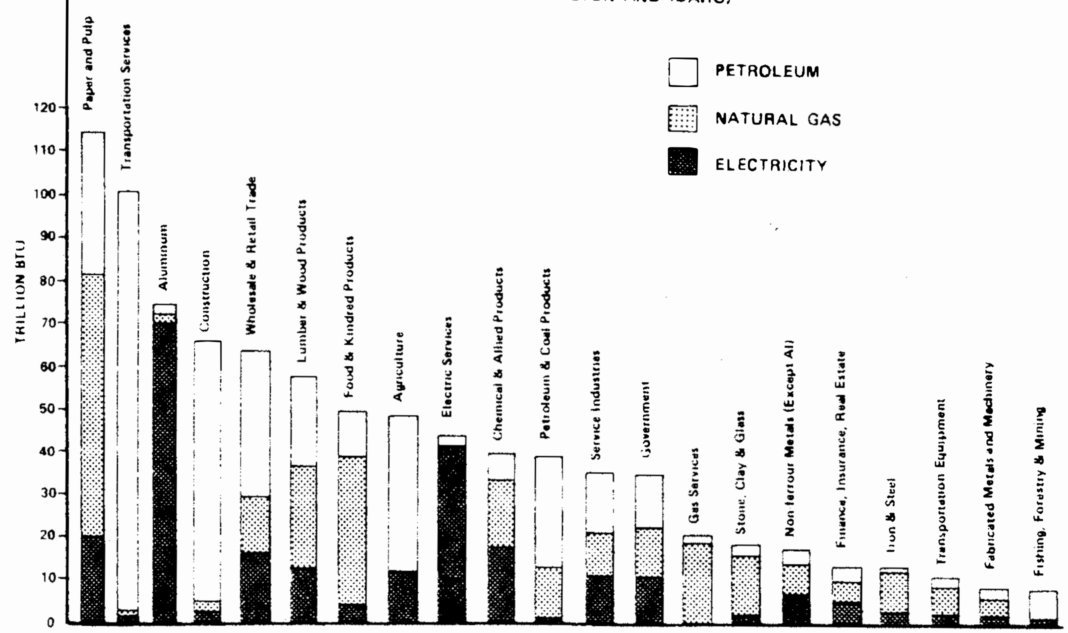
INDUSTRIAL ELECTRICITY PRICE ELASTICITIES 1/

SIC	Industry	Anderson, 1976, p. 20	NERA, 1976	Wilson, 1969, p. 114	Halvorsen, 1977, Table 7	Fisher & Kaysen, 1962, p. 135	Wilson, 1974, p. 423	Economet-rica 1977, p. 97
20	Food	-0.44		-0.87		-0.78	-1.09	-1.26
22	Textiles		-0.63	-1.17		-1.62	-1.22	-2.01
23	Apparel				-0.15			-0.85
24	Lumber	-0.49		-1.17				-0.85
25	Furniture						-0.97	-0.52
26	Pulp & Paper	-1.13	-0.56	-2.31		-0.97	-1.48	-1.01
27	Printing							
28	Chemicals	-1.62	-0.91	-2.13	-0.68	-2.60	-2.23	-2.60
29	Petroleum	-0.55	-0.91		-1.03			-1.73
30	Rubber							-0.01
31	Leather			-0.86			-0.76	-0.89
32	Stone, Clay & Glass	-1.00		-1.59		-1.74	-1.08	-1.04
33	Primary Metals	-1.46	0.98	-1.98	-0.83	-1.28	-1.51	-1.39
34	Fabricated Metals	-0.74			-1.10			-0.65
35	Machinery	-1.52		-0.52	-0.79	-1.33	-1.16	-3.80
36	Electrical Equipment	-0.42		-1.06	-0.27	-1.82	-1.76	-1.03
37	Transportation	-0.31		-0.52			-1.01	-1.42
38	Instruments							-0.80
39	Miscellaneous Mining	-1.02						-0.10

1/ Only those estimates significant at the 0.10 level or better are listed. A blank means the study did not estimate an elasticity coefficient for that industry or the estimates were statistically insignificant. Econometrica did not provide significance tests (the Cobb-Douglas profit function is displayed here).

Figure V-5

ENERGY CONSUMPTION IN PACIFIC NORTHWEST INDUSTRIES, 1971
(OREGON, WASHINGTON AND IDAHO)



SOURCE Walter Butcher and George Hinman, Guidelines for a Northwest Energy Policy, Phase , Pullman, Washington: Environmental Research Center, Washington State University, April 1971, pp. 22-23

Table V-7

ELECTRICITY PURCHASES AS A PERCENT OF VALUE ADDED, PACIFIC NORTHWEST, 1972

Input-Output Sector	Estimated Electricity Purchases (million $)	Value Added (million $)	Percent
Crops	10.06	1,176.0	0.8
Livestock	8.83	403.1	2.2
Food Processing	14.79	1,209.0	1.2
Textiles & Apparel	0.9	94.4	0.9
Mining	10.14	144.7	7.0
Forestry & Fishing	0.4	285.4	0.1
Lumber	27.09	2,007.7	1.3
Plywood	13.4	626.6	2.1
Pulp & Paper	29.7	763.7	3.9
Chemicals	22.5	340.7	6.6
Petroleum Refining	3.7	127.5	2.9
Stone, Clay & Glass	5.3	193.5	2.7
Iron & Steel	5.85	112.6	5.2
Non-Ferrous Metals	7.06	77.8	9.1
Aluminum	43.9	315.2	13.9
Fabricated Metals	5.54	663.8	0.8
Electrical Machinery	1.84	146.1	1.3
Aircraft & Aerospace	3.95	875.0	0.5
Other Manufacturing	7.45	1,146.6	0.6
Transportation Services	12.78	1,688.5	0.8
Construction	4.77	1,554.6	0.3
Trade	101.99	5,517.4	1.8
Services	91.27	6,015.2	1.5

Source: John Wilkins, Construction of A Multi-Regional Input-Output Model for the Pacific Northwest, Portland, OR: Northwest Energy Policy Project, 1978.

CERCDC, 1978, p. IV-48) have similarly concluded that only a relatively few industries devote a significant portion of production costs to electricity purchases. BPA's direct-service industrial customers, discussed in detail later, are certainly among those few industries. Mining operations, pulp and paper mills, steel mills, and cement plants would also be more than proportionately affected by an electricity rate increase.

c. Effects on Economic Growth. Many researchers have examined the potential impact of energy or electricity price increases on industrial output, employment, and other economic indicators. At the simplest level, it has been pointed out that "since energy costs are less than 5 percent of total costs for almost all sectors, and less than 1 percent for many sectors, the impact of even a doubling in energy price would not be catastrophic for most businesses. Cost increases of that magnitude are encountered quite regularly due to wage increases and either borne internally or passed on to customers in product price increases" (Butcher and Hinman, 1974, p. 53). This view is supported by several researchers (LADWP, 1977, p. III-18; Nissel, 1976, p. 3; Ontario Hydro, 1977, vol. XA, p. 4). On the other hand, it should be noted that the figures listed in Table V-7 are industry averages, and for some individual firms the impacts could be much greater. The profit margins of some operations may be as low as 0.5 percent or less of gross sales, and a large increase in electricity rates could significantly affect them (CERCDC, 1978, p. IV-49; Electrical Week, March 6, 1978, p. 3).

On a larger economic scale, it can be expected that rate increases will have the immediate effect of increasing production costs, which in turn will cause output prices to increase, thus depressing demand for manufactured goods (Chern, 1975, p. 40). The competitive positions of less electricity-intensive firms will be improved relative to firms which consume more electricity per unit of output if the prices of other production factors remain constant.

Jensen Associates (1977, p. 10) attempted to quantify the nationwide impact on output and employment of a rate structure which would increase the price of electricity to the industrial sector by approximately 50 percent in real terms. They concluded that during the period 1977-1979, gross national product would be $9.9 billion lower, employment would be reduced by 430,000 man-years, and disposable income would be down by $2.9 billion. Nevertheless, these numbers, while impressive from an absolute perspective, represent only about 0.2 percent of their respective economic indicators for those years. Furthermore, these levels would represent the maximum effect since the model which was used by Jensen Associates did not take into account the ways in which industry would change its purchasing of materials, selection of production processes, or use of existing capital equipment and labor force.

Several studies have shown that, in the long run, energy serves as a substitute for both capital and labor; thus as the price of energy increases, the use of energy efficient equipment and more labor-intensive processes would increase (Hudson and Jorgenson, 1974, p. 503; Berndt and Wood, 1975, p. 260; Griffen and Gregory, 1976, p. 852; Fuss, 1977, p. 109; and Savitt, 1976, p. 125; Chern, 1975, p. 31 reports conflicting results). While it might seem that employment should decrease significantly as a result of an electricity price increase, actually the energy-labor substitution effect should substantially mitigate employment loss (Hogan and Manne, 1977, p. 258). Although individual industries and firms may sustain a production and employment loss, other industries may gain.

d. Electric Consumption for Pacific Northwest Commercial Establishments and Industries in 1997

If Bonneville were to adopt its proposed rates, electricity use by Pacific Northwest businesses and industries would be expected to be 2,543 million kWh lower than it would be without the rate increase. Fuel oil consumption would rise by 8,053 million gallons and natural gas use would increase by 14,539 million therms as well.

The impacts of the other revenue alternatives would of course vary, but those impacts (given in Table IV-3) are proportionate to those mentioned here.

3. Effects on Irrigation Customers. Approximately 5 percent of the power BPA sells to its preference customers is ultimately sold to farmers for irrigation. Northwest farmers have traditionally enjoyed low power costs and consequently have invested heavily in electrically powered irrigation systems. They have been able to turn previously nonirrigated acreage into good irrigated farmland. This advantage has, however, been offset by the Pacific Northwest farmer's relatively high transportation costs to get his product to the national markets.

a. Bonneville's Study. Bonneville's price increase will tend to diminish the farmers' competitive advantage. As a result, Northwest farmers have expressed grave concerns about BPA's proposed rates and would like very much to see a return to the "irrigation discount" which was eliminated in 1974. (See Section C.8 of Chapter VI (page VI-65) for a discussion of this topic.) Because Bonneville shares their concern about the potential effects of the rate proposal, BPA contracted with a group of university researchers from agricultural economics departments at Washington State University, the

University of Idaho, and Oregon State University to study the effects of an increase in electricity prices on Pacific Northwest irrigators. The group was headed by Dr. Norman Whittlesey of Washington State University. The study concluded that irrigators could make some adjustments to increasing electricity rates, but would, nonetheless, still be hurt.

The study attempted to consider first how existing irrigated farms would respond to an increase in electricity prices. In the short run (through 1985), potential adjustments would be made in water application, pump efficiencies, and amounts of acreage devoted to production of specific crops. For instance, water application efficiencies were assumed to increase 5 percent and pumping plant efficiencies were assumed to improve 10 percent. In the long run (through 2020), potential adjustments may include those described for the short run plus new technology, changed irrigation systems (e.g., switching from less efficient side roll systems to center pivot systems), and reduction of irrigated acreage. Projections of new irrigation development were made under alternative assumptions of electricity price increases to complete the picture of demand for electricity by agriculture.

Table V-8 shows a wide range in the 1975 average price paid by irrigators for electricity in some parts of the region. The rates shown are weighted averages of different utilities' selling prices of electricity within the subareas, excluding power provided by Bureau of Reclamation projects (Col. 2). The weighted average regional price to irrigators is estimated to be 11.93 mills/kWh. In assessing the response to a price increase, Whittlesey, et. al., applied uniform increases of 6, 12, 24, and 48 mills per kWh to the subarea values shown in Table V-8 to estimate electricity prices associated with 50, 100, 200, and 400 percent increases in cost. The researchers used a computer model which assumed that farmers adjust to changes in the prices of production input in ways that would maximize profits. Data on farm operation costs, irrigation systems, crop mixes and prices, and other factors were held constant in the computer model so that predictions could be made about potential reactions to real electricity price increases.

The report concluded that, in the short run, the major responses to an electricity price increase may be managerial improvements resulting in higher efficiencies in the application of water and operation of electrical pumps and in changes in crop acreages to reduce water and electricity use. These changes were estimated to result in an 18 percent reduction in electricity use through 1985 by existing

Table V-8

IRRIGATION ELECTRICITY SUPPLIERS AND RATES, 1975

Subregion	Composite Electricity Rate (Mills/kWh)	Percent Supplied by: Bureau of Reclamation	Percent Supplied by: Publicly Owned Utilities or Cooperatives	Percent Supplied by: Investor Owned Utilities
Washington:				
Big Bend	9.32	60	36	4
Puget Sound	12.04	---	86	14
North Side Columbia	8.43	---	100	---
Spokane	10.86	17	22	61
Yakima	11.27	17	42	41
Oregon:				
Willamette	19.34	---	9	91
Deschutes	14.37	10	45	45
Umatilla	9.17	---	93	7
Klamath	15.75	---	10	90
Ontario	12.90	---	23	77
Idaho:				
Southwest	11.82	12	---	88
South Central	11.50	15	13	72
Southeast	14.81	12	4	84
Montana (Western)[a]	15.164	[b]	65	35

[a] 1977 data.
[b] Unavailable.

Source: Norman K. Whittlesey, et. al., Demand Response to Increasing Electricity Prices by Pacific Northwest Irrigated Agriculture, Departments of Agricultural Economics, University of Idaho, Oregon State University, and Washington State University, July 1978, p. 12.

irrigators in response to a doubling of electricity prices (a short-run price elasticity of -0.30).1/ Only a small amount of this reduction in electricity use is due to crop shifts.

In the long run, with doubling energy prices (100 percent retail price increase), energy demand may be 36 percent below what it would have been without the increase. In addition to the short-run factors discussed above, farmers may adopt new, energy-efficient technology (e.g., low pressure pumps), to switch to more efficient irrigation systems, and as a last resort, to reduce the number of acres irrigated. Table V-9 provides a summation of the changes in electricity demand in the short run and long run due to varying increases in electricity prices.

The reduction in irrigated acreage was significant for large rate increases. A 100 percent retail increase would, by 2020, result in an approximate decrease in currently irrigated land of 140,000 acres, while 441,000 fewer acres of new irrigated land would be expected to be developed than would be the case under existing rates. These figures represent about a 10 percent decline from the 5,727,000 in total irrigated acreage expected in 2020 without the rate increase. A 200 percent rate increase to irrigators would result in a decline of an additional 10 percent in irrigated acres. These lands would primarily be at higher elevations requiring greater pump lifts, and they would be either dry farmed or would cease to be farmed.

A final section of the Whittlesey, et. al., report assessed the economic viability of irrigators switching to other fuels (diesel oil, natural gas, or propane) as a response to increasing electricity prices. It concluded that electricity will continue to be the only source of power for irrigation in the Pacific Northwest for any retail electricity rate increase of less than 400 percent.

b. Impact on Agricultural Production Costs. The following analysis attempts to quantify the actual impact of BPA's rate increase on farmers. Table V-10 shows the typical market value (on an acre basis) of the three crops under consideration: wheat, alfalfa, and potatoes.

1/ For every 1 percent increase in pumping electricity price, demand will decrease by .3 percent.

TABLE V-9

PACIFIC NORTHWEST ELECTRICITY CONSUMPTION (MILLIONS OF KILOWATTHOURS), CURRENT AND PROJECTED IRRIGATION AT ALTERNATIVE ELECTRICITY PRICE LEVELS[1/]

Subregion	Current	Short-Run Percent Price Increase at the retail level		Long-Run Percent Price Increase at the retail level			
		50	100	0	100	200	400
Idaho:							
Southwest	401	348	341	875	479	427	74
South Central	521	454	448	731	461	452	258
Southeast	874	729	729	1,221	936	709	79
Subtotal	1,796	1,531	1,518	2,827	1,876	1,588	411
Washington:							
Northern Idaho	85	65	65	85	44	43	42
Upper Columbia	898	701	697	2,404	1,851	1,725	1,452
Yakima	52	41	36	87	52	50	7
Lower Snake	47	38	38	490	24	22	14
Mid-Columbia	376	314	311	1,479	748	93	45
Coastal	17	14	14	17	8	7	7
Puget Sound	78	64	64	78	38	38	38
Subtotal	1,553	1,237	1,225	4,640	2,745	1,978	1,605
Montana (Western)	83	64	64	83	83	15	-
Oregon:							
Mid-Columbia	546	461	461	1,256	976	727	342
Willamette	148	125	123	363	297	224	220
Other	286	231	231	440	240	175	128
Subtotal	980	817	815	2,060	1,513	1,127	690
TOTAL	4,534	4,412	3,622	9,650	6,149	4,708	2,706

1/ Percents are based on an average retail rate of 1.2 cents per kWh.

Source: Norman K. Whittlesey, et. al., _Demand Response to Increasing Electricity Prices by Pacific Northwest Irrigated Agriculture_, Departments of Agriculture Economics, University of Idaho,

TABLE V-10
TYPICAL MARKET VALUE OF
COMMON PACIFIC NORTHWEST CROPS
(average of 1975-1977 prices)

COMMON PACIFIC NORTHWEST CROPS	TYPICAL MARKET VALUE OF
Wheat	$ 300/acre
Alfalfa	$ 360/acre
Potatoes	$1,375/acre

Source Norman K. Whittlesey, et. al., Demand Response to Increasing Electricity Prices by Pacific Northwest Irrigated Agriculture, Departments of Agricultural Economics, University of Idaho, Oregon State University, and Washington State University, April 1979, p. I-5.

Table V-11 estimates kWh consumption per acre for various climates, lifting requirements, crops, and types of irrigation systems in use.

The effect of BPA's wholesale power rate increase on farmers who rely on electrically powered pumps and sprinkler systems to irrigate their farmland will be dependent on a number of factors. A meaningful "average" irrigation rate for a particular utility generally does not exist, so BPA has drafted Figure V-6 to give the reader an idea of the expected range of average irrigation rates in 1980. This figure was derived from the 1977 financial statements of the irrigation utilities. The specific average rate to a given farmer will depend not only on his utility's rate structure, but also on the size of his load and his level of use. A farmer billed under a combined demand/energy rate could minimize his bill by operating his equipment at the same level, 24 hours a day (100 percent load factor). A farmer billed under a different type of rate structure, such as a connected horsepower plus energy charge, would not find it advantageous to worry about when he used his irrigation system. The reader is encouraged to examine his own power bill in order to estimate his existing average rate. By adding the wholesale millage increases shown in Table V-2 to this average rate, he will have a good idea of what his overall rate will probably be after BPA's rate increase. Of course, if a utility has "ramped" or if the utility changes its rate structure when it raises its rates, the new average rate may not resemble that derived above.

TABLE V-11 1/

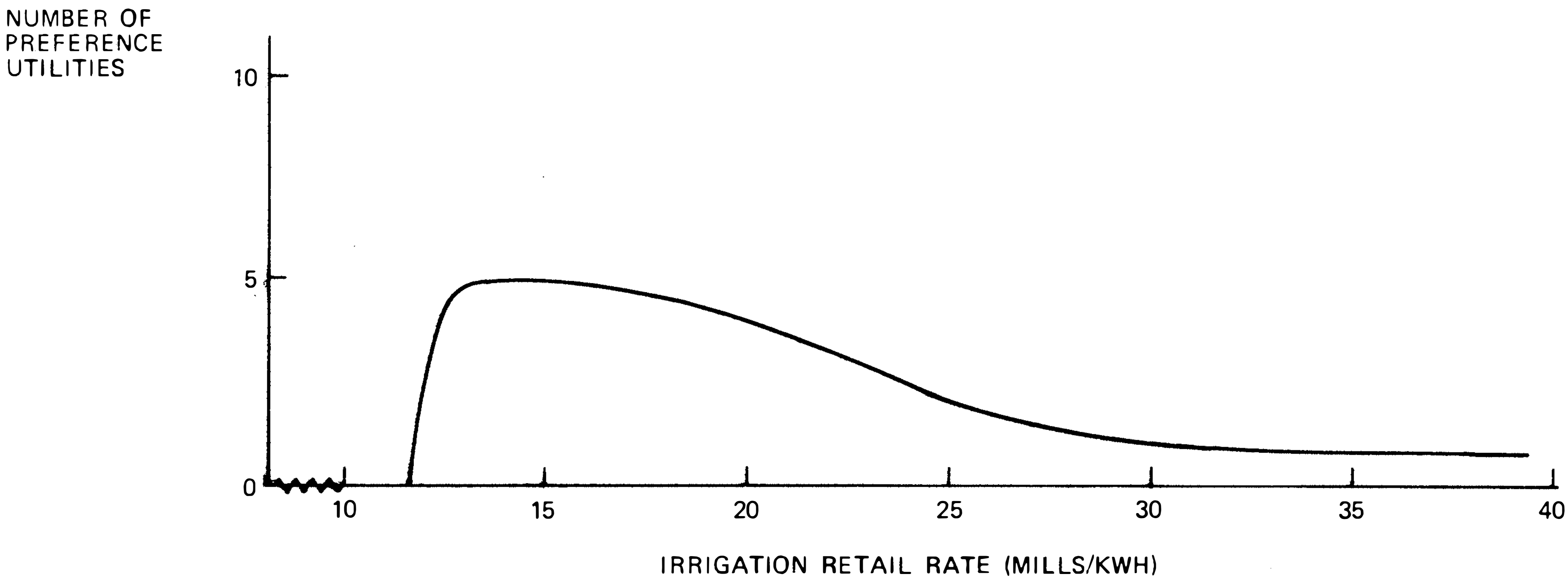
Electricity Consumption for Irrigation
By Climate, Lift, Crop, and Type of Irrigation System

Climate	Lift	Typical Subregion	Type of Irrigation System	Electricity Consumption (kWh/acre) Wheat	Alfalfa	Potatoes
Dry	High	Umatilla	center pivot	1542	2716	1744
			side roll	1287	2268	1456
			gravity	269	474	304
Dry	Low	Malheur	center pivot	1681	2676	2043
			side roll	1571	2508	1915
			gravity	320	510	389
Medium	High	Spokane	center pivot	1470	2304	2053
			side roll	1463	2292	2043
			gravity	894	1401	1248
Medium	Low	Deschutes	center pivot	1276	1833	1157
			side roll	1192	1713	1081
			gravity	216	311	196
Wet	Medium	Willamette	center pivot	584	1339	755
			side roll	527	1209	681
			gravity	187	430	242

1/ Data from "Energy and Water Consumption of Pacific Northwest Irrigation Systems," Battelle PNW Laboratories pp. 88, 68, 20, 93, 100

2/ Weighted average of groundwater and surface water figures based on type of pumping lifts in each area.

Figure V-6



DISTRIBUTION OF THE PROJECTED AVERAGE IRRIGATION RETAIL RATES
FOR BPA'S PREFERENCE CUSTOMERS

Once the irrigation retail rate has been ascertained, and the farmer knows how many kilowatthours he can expect to use for each acre that he plants (based on climate, crop, lifting conditions and type of irrigation system used), he can determine his expenditures on electricity from Table V-12. By consulting Table V-13, he can see what percent of the typical selling price for his product will be spent on power costs. If the reader has better information than that shown in Tables V-10 through V-13 he should use his own data in order to get the most accurate picture of what the effects of this rate increase will be on him.

c. Social Impacts on Irrigators As a result of BPA's rate increase, it is probable that most irrigators will attempt to run their operations more efficiently. Some "marginal" farmers may find it uneconomical to continue their operations and would therefore sell their property.1/ These displaced farmers would have to seek employment elsewhere, either working for another farmer or getting an entirely different type of job. However, BPA's wholesale power rate increase is not expected to actually cause any irrigated land to be taken out of production, as other farmers are expected to purchase the land put up for sale by the marginal farmers.

Many of the farmers who are dependent on BPA's electricity to power their irrigation systems have expressed concerns that BPA's rate increase would drive them out of business. If they were unable to continue farming and no other individual or enterprise were able to farm the property at a profit, it is true that the economy of the Pacific Northwest would be slightly depressed. Fewer acres in production would mean fewer farmhands with a job, fewer truckers hauling the produce to canneries, fewer workers in the packing and other supporting industries, and higher prices for Pacific Northwest produce.

However, according to a study done for Bonneville to determine the effects of a price increase on irrigation (Whittlesey, 1979), a short-run retail rate increase to irrigators of 50 percent would not cause any irrigated acreage to be taken out

1/ Norman K. Whittlesey, et. al., Demand Response to Increasing Electricity Prices by Pacific Northwest Irrigated Agriculture, Departments of Agricultural Economics, University of Idaho, Oregon State University, and Washington State University, April 1979, p. I-11.

TABLE V-12

ELECTRICITY COSTS PER ACRE
(Dollars)

Mills/KWH

		10	12	14	16	18	20	22	24	26	28	30	32	34	36	38	40
KWH/ACRE	100	1.00	1.20	1.40	1.60	1.80	2.00	2.20	2.40	2.60	2.80	3.00	3.20	3.40	3.60	3.80	4.00
	200	2.00	2.40	2.80	3.20	3.60	4.00	4.40	4.80	5.20	5.60	6.00	6.40	6.80	7.20	7.60	8.00
	300	3.00	3.60	4.20	4.80	5.40	6.00	6.60	7.20	7.80	8.40	9.00	9.60	10.20	10.80	11.40	12.00
	400	4.00	4.80	5.60	6.40	7.20	8.00	8.80	9.60	10.40	11.20	12.00	12.80	13.60	14.40	15.20	16.00
	500	5.00	6.00	7.00	8.00	9.00	10.00	11.00	12.00	13.00	14.00	15.00	16.00	17.00	18.00	19.00	20.00
	600	6.00	7.20	8.40	9.60	10.80	12.00	13.20	14.40	15.60	16.80	18.00	19.20	20.40	21.60	22.80	24.00
	700	7.00	8.40	9.80	11.20	12.60	14.00	15.40	16.80	18.20	19.60	21.00	22.40	23.80	25.20	26.60	28.00
	800	8.00	9.60	11.20	12.80	14.40	16.00	17.60	19.20	20.80	22.40	24.00	25.60	27.20	28.80	30.40	32.00
	900	9.00	10.80	12.60	14.40	16.20	18.00	19.80	21.60	23.40	25.20	27.00	28.80	30.60	32.40	34.20	36.00
	1000	10.00	12.00	14.00	16.00	18.00	20.00	22.00	24.00	26.00	28.00	30.00	32.00	34.00	36.00	38.00	40.00
	1100	11.00	13.20	15.40	17.60	19.80	22.00	24.20	26.40	28.60	30.80	33.00	35.20	37.40	39.60	41.80	44.00
	1200	12.00	14.40	16.80	19.20	21.60	24.00	26.40	28.80	31.20	33.60	36.00	38.40	40.80	43.20	45.60	48.00
	1300	13.00	15.60	18.20	20.80	23.40	26.00	28.60	31.20	33.80	36.40	39.00	41.60	44.20	46.80	49.40	52.00
	1400	14.00	16.80	19.60	22.40	25.20	28.00	30.80	33.60	36.40	39.20	42.00	44.80	47.60	50.40	53.20	56.00
	1500	15.00	18.00	21.00	24.00	27.00	30.00	33.00	36.00	39.00	42.00	45.00	48.00	51.00	54.00	57.00	60.00
	1600	16.00	19.20	22.40	25.60	28.80	32.00	35.20	38.40	41.60	44.80	48.00	51.20	54.40	57.60	60.80	64.00
	1700	17.00	20.40	23.80	27.20	30.60	34.00	37.40	40.80	44.20	47.60	51.00	54.40	57.80	61.20	64.60	68.00
	1800	18.00	21.60	25.20	28.80	32.40	36.00	39.60	43.20	46.80	50.40	54.00	57.60	61.20	64.80	68.40	72.00
	1900	19.00	22.80	26.60	30.40	34.20	38.00	41.80	45.60	49.40	53.20	57.00	60.80	64.60	68.40	72.20	76.00
	2000	20.00	24.00	28.00	32.00	36.00	40.00	44.00	48.00	52.00	56.00	60.00	64.00	68.00	72.00	76.00	80.00
	2100	21.00	25.20	29.40	33.60	37.80	42.00	46.20	50.40	54.60	58.80	63.00	67.20	71.40	61.20	79.80	84.00
	2200	22.00	26.40	30.80	35.20	39.60	44.00	48.40	52.80	57.20	61.60	66.00	70.40	74.80	79.20	83.60	88.00
	2300	23.00	27.60	32.20	36.80	41.40	46.00	50.60	55.20	59.80	64.40	69.00	73.60	78.20	82.80	87.40	92.00
	2400	24.00	28.80	33.60	38.40	43.20	48.00	52.80	57.60	62.40	67.20	72.00	76.80	81.60	86.40	91.20	96.00
	2500	25.00	30.00	35.00	40.00	45.00	50.00	55.00	60.00	65.00	70.00	75.00	80.00	85.00	90.00	95.00	100.00
	2600	26.00	31.20	36.40	41.60	46.80	52.00	57.20	62.40	67.60	72.80	78.00	83.20	88.40	93.60	98.80	104.00
	2700	27.00	32.40	37.80	43.20	48.60	54.00	59.40	64.80	70.20	75.60	81.00	86.40	91.80	97.20	102.60	108.00
	2800	28.00	33.60	39.20	44.80	50.40	56.00	61.60	67.20	72.80	78.40	84.00	89.60	95.20	100.80	106.40	112.00
	2900	29.00	34.80	40.60	46.40	52.20	58.00	63.80	69.60	75.40	81.20	87.00	92.80	98.60	104.40	110.20	116.00
	3000	30.00	36.00	42.00	48.00	54.00	60.00	66.00	72.00	78.00	84.00	90.00	96.00	102.00	108.00	114.00	120.00

TABLE V-13

ELECTRICITY COSTS AS A PERCENT OF TYPICAL MARKET VALUE
FOR WHEAT, ALFALFA, AND POTATOES

PRODUCTION COST PER ACRE (Dollars)	PERCENT OF TYPICAL MARKET VALUE FOR WHEAT @ $300/acre	PERCENT OF TYPICAL MARKET VALUE FOR ALFALFA @ $360/acre	PERCENT OF TYPICAL MARKET VALUE FOR POTATOES @ $1,375/acre
10	3.33	2.78	0.73
15	5.00	4.17	1.09
20	6.67	5.56	1.45
25	8.33	6.94	1.82
30	10.00	8.33	2.18
35	11.67	9.72	2.55
40	13.33	11.11	2.91
45	15.00	12.50	3.27
50	16.67	13.89	3.64
55	18.33	15.28	4.00
60	20.00	16.67	4.36
65	21.67	18.06	4.73
70	23.33	19.44	5.09
75	25.00	20.83	5.45
80	26.67	22.22	5.82
85	28.33	23.61	6.18
90	30.00	25.00	6.55
95	31.67	26.39	6.91
100	33.33	27.78	7.27
105	35.00	29.17	7.64
110	36.67	30.56	8.00
115	38.33	31.94	8.36
120	40.00	33.33	8.73

of production.1/ Since BPA's increase would cause most utilities' wholesale power costs to rise by something less than 100 percent and because wholesale costs generally represent approximately half of retail costs, (see Table V-3) it is most probable that no land would be taken out of production as a result of BPA's rate increase. The farmers would, however, be affected because it is unlikely that they would be able to increase the price they receive for their products to offset their increased costs of power. Consequently, their incomes will be reduced by the amount of the increased costs they must absorb.

C. Effects on BPA's Direct Service Customers. Although Bonneville is primarily a wholesaler of electric power, there are a number of customers, such as the direct-service industries (DSIs) and some Federal agencies, which purchase power directly from Bonneville. Clearly a BPA rate increase would directly affect these customers and require them to adjust their operations to either conserve energy or allow for increased expenditures for power. The revenue alternative used to develop BPA's rates would in large part determine the magnitude and type of impact that a rate increase would have on these customers.

1. Effects on Direct Service Industries. BPA directly serves 15 industrial customers which operate 21 plants throughout the Northwest. Indications are that these industries would not change their operations in response to a BPA rate increase unless, perhaps, BPA were to charge marginal cost rates (cf., Charles River Associates, 1978, p. 109). See Table V-1 for a comparison of the average rates under the existing and proposed schedules.

In 1976, Ernst & Ernst analyzed the impact of several pricing alternatives on BPA aluminum customers and determined that a rate of 9 to 12 mills/kWh would bring costs of the Pacific Northwest plants up to levels comparable to other U.S. plants (p. V-43), while, in the short run, costs of up to 21 mills/kWh could be absorbed without forcing a shutdown. Recently the President's Council on Wage and Price Stability updated the short-run shutdown cost analysis and determined the break-even power cost level to be from 23.9 to 33.0 mills/kWh (Bosworth, 1978, P. 4). No detailed studies of the non-aluminum direct-service industries have been made, but since power costs represent a smaller proportion of the total costs of non-aluminum companies than is true of the aluminum companies, there is no reason to believe that these industries would not also be able to absorb rates of 9 to 12 mills/kWh. According to Charles River Associates (1978, pp. 110, 115), the Hanna Nickel Plant in Riddle, Oregon, and Carborundum's silicon carbide plant in Vancouver, Washington, would be the most susceptible to electricity price increases.

1/ Norman K. Whittlesey, et. al., Demand Response to Increasing Electricity Prices by Pacific Northwest Irrigated Agriculture, Department of Agricultural Economics, University of Idaho, Oregon State University, and Washington State University, July 1978, p. 36.

It is possible that the increased costs to these customers would be passed on in the form of increased prices for their products. If this happens, it could affect the long-run demand for those products. For example, the price elasticity of demand for aluminum ingot is estimated to be approximately -1.0 (Pindyck, 1977, p. 346), indicating a 1 percent increase in price would reduce demand for aluminum ingot by 1 percent.

2. Effects on Federal Agencies. The alternative revenue levels considered in this chapter are not expected to have a significant impact on the Federal agencies served by BPA. There are only six agencies in the Northwest which receive firm BPA power. The ultimate effect of a rate increase would be on the U.S. taxpayer, because these Federal agencies receive funding through the Federal Treasury. However, because power costs represent such a minor portion of the overall budgets for these agencies, the impacts on the U.S. taxpayer would be extremely small.

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CHAPTER VI

RATE DESIGNS AND THEIR IMPACTS

A. Introduction

A discussion of the various amounts of revenue which Bonneville might reasonably seek to recover through its wholesale power rates was presented in Chapter III. In general, the higher the amount of revenue BPA seeks to recover, the higher will be the rates required. The decision regarding the amount of revenue to be recovered is, by far, the most significant factor in determining the level at which Bonneville will establish its wholesale power rates for various services.

If Bonneville provided only a single type of service and had only one rate for that service, the amount of revenue to be recovered would be the sole determinant of that rate. Such is not the case, however, for Bonneville provides a diversity of services to several types of customers and charges them a number of different rates. These rates are based on a variety of criteria. The manner of application of these criteria introduces the factor of rate design into Bonneville's rate development process. Rate design has much less impact on wholesale power rates than does the revenue level which the rates are intended to derive; however, it can have a significant impact on the distribution of the revenue burden across Bonneville's various customers and therefore on the demand for and use of electricity and associated environmental impacts. This chapter is focused on the potential which the design of BPA rates has for impacting customers' purchasing power and how this might result in environmental effects.

B. Goals and Principles of Rate Design

Rate design principles and goals currently generate a great deal of discussion. In Public Utility Economics, Garfield and Lovejoy state the guiding principles in rate formation as follows: (1) the costs of supplying each class of customers or service, and (2) the value of service. Ratemaking goals are numerous and complex. Following is a list of generally accepted traditional ratemaking objectives:

1. Simplicity, understandability, public acceptability, and feasibility of application;

2. Freedom from controversy about proper interpretation;

3. Effectiveness in yielding total revenue requirements under the fair-return standard;

4. Revenue stability from year to year;

5. Stability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to existing customers;

6. Fairness of specific rates in the apportionment of total costs of service among the consumers;

7. Avoidance of undue discrimination in rate relationships;

8. Efficiency of rate classes and rate blocks in discouraging the waste of resources while promoting all justified types and amounts of use;

   a. By controlling the total amount of service supplied by the utility;

   b. By controlling the relative use of alternative types of service (peak versus offpeak electricity). (Bonbright, 1961, p. 291.)

One means of accomplishing these objectives has been to develop cost-based rates. In order to develop cost-based rates a utility must conduct a cost-of-service study which identifies the proportion of total costs (customer, energy, and demand costs) associated with providing electric service to each customer class. Rates are then established at levels which will recover revenues from customers in proportion to the service costs allocated to those customers.

Rates can, however, be designed to attain various other pricing objectives while still meeting the financial objective of recovering costs. Alternative pricing objectives include economic efficiency, fairness, redistribution of wealth, social welfare, conservation, and environmental protection. (See Volume VI of Ontario Hydro's Electricity Costing and Pricing Study for a discussion of these objectives.)

The basic rate design objectives Bonneville has followed for its wholesale power rates include: (1) revenues must be adequate to meet BPA's repayment obligation (see Chapter II, Section D.2.); (2) in meeting the revenue requirements the burden should be distributed in an equitable manner among recipients of the service; (3) rates should be designed to encourage conservation and minimize environmental impacts; and (4) rates should be designed to encourage efficient use of the Federal Columbia River Power System (FCRPS) by reflecting costs incurred and benefits received.

In developing the wholesale power rate proposal Bonneville has been guided by these objectives. Additionally, consideration was given to rate continuity, ease of administration, revenue stability, and ease of understanding (BPA, 1979a).

The rates which Bonneville is proposing to implement on December 20, 1979 are designed primarily to reflect the criteria of cost of service, value of service, and economic efficiency. Some of the design features which will be discussed are more directly focused on the objectives of equity, conservation and environmental protection.

The Use of Cost of Service in Designing Rates.

A cornerstone of Bonneville's effort to develop its rate proposal has been the completion of a detailed and comprehensive study of the costs incurred by BPA in providing specific types of services to each of its customer classes. Although Bonneville's existing rates include cost-of-service considerations, they were developed without benefit of a fully allocated cost-of-service analysis which Bonneville has now completed.

In developing its cost-of-service study, BPA has endeavored to follow, to the extent practicable, generally accepted cost-of-service methodology as applied in the utility industry.

The general concept is to first delineate the investment in facilities (investment base) used to provide service. Annual costs for operation, maintenance, and depreciation also are developed. The investment base and annual costs are then functionalized, i.e., segmented by the major functions perfomed by the power system. In the case of the FCRPS, these functions are defined as (1) generation, (2) transmission, and (3) metering and billing. All costs are assigned to one or another of these functions. The costs functionalized to generation are then classified to the two subfunctions of (1) generating capacity and (2) energy production.

In developing its proposal, BPA allocated costs according to service categories so that the cost-of-service would parallel rate schedules. The service classes include power rates, wheeling rates, and other services and revenues. The power rate categories were further divided into subcategories, such as firm power, reserve power, industrial firm power, modified firm power, firm capacity, firm energy, and nonfirm energy.

The costs of transmission facilities leased to others are assigned directly to the lessees. Similarly, the costs of transmission facilities charged for on a use-of-facility basis (where the charge is based on the cost of the specific facilities or types of facilities actually used) are assigned directly to the use-of-facility customer category. The costs of all transmission facilities not specifically assigned are assigned to the transmission system.

The functionalized and classified investment base and annual costs of the generating facilities and the transmission system are then allocated among the service categories based upon the application of allocation factors which reflect the demands the various service categories place upon the generation and transmission systems.

Total revenue requirements are determined based upon a repayment study which determines the amount of revenue required to meet all financial obligations of the power system. The revenue requirement is then allocated to the service categories.

Once all costs have been functionalized, classified, and allocated to the various customer categories, rates must be designed in such a way as to recover the appropriate cost amounts. Cost determination is a part of the rate design process. Cost determination involves the establishment of a methodology or technique to determine the cost of providing service. The cost study is the starting point for rate design.

With the exceptions of the proposed rates for firm capacity and nonfirm energy sales, the design features in Bonneville's proposed rates are intended to primarily reflect cost-of-service pricing. A discussion of the rate designs Bonneville is proposing along with the features of its existing rates and a variety of rate design alternatives follows.

C. Analysis of Rate Designs and Their Impacts.

1. Differentiation of Rates by Service Components.

a. Discussion of the Design Concept. As previously indicated, the cost of providing utility service is generally divided into three components: generation costs (which are further broken down into those costs associated with generating capacity and those stemming from energy production), transmission costs, and customer costs such as metering and billing. Bonneville recovers these costs (with the exception of that portion allocated to wheeling customers) through its wholesale power rates. The power rates consist of a demand charge and an energy charge. The demand charge is intended to reflect customer costs, transmission costs and generation capacity costs. The energy charge is intended to reflect the cost of energy production. Under the proposed classification method employed in BPA's cost-of-service analysis, Bonneville's costs are nearly equally split between capacity and energy. However, the rate design process has resulted in a modification of this cost assignment to reflect the increasing cost of energy which BPA will be facing in the next few years.

Several methods can be used in the design of capacity and energy rates. The method selected will have a unique effect on the average power cost paid by each utility purchasing power from BPA.

The term "load factor" refers to the ratio of a customer's average demand to its peak demand. The relative costs of energy and capacity may influence customer load factors by encouraging them to either increase or decrease their capacity requirements in relation to their energy requirements. Recovery of all energy and capacity costs through a demand charge would provide utilities with a strong incentive to take power at as uniform a rate as possible in order to minimize their peak demand and, therefore, their average cost for power. This would encourage high load factors. Recovery of all power costs through an energy charge, however, would provide no incentive for utilities to minimize their peak demands.

Due to the metering costs involved in monitoring both peak demand and energy consumed, most retail power consumers are charged only an energy rate which recovers both capacity and energy costs. In Bonneville's case, however, the demands of its wholesale customers are large enough to justify the cost of metering both demand and energy and charging separate rates for each. Furthermore, failure by BPA to assess a capacity charge against its customers would result in less efficient utilization of BPA's resources than would be the case if utilities were given an incentive to limit their peak demands. On the other hand, recovery of all power costs from a capacity charge would not provide sufficient incentive to utilities to constrain their energy requirements. Efficient use of energy is also a serious concern of Bonneville, especially in view of the fact that the Federal System will soon be unable to meet all the energy requirements of its customers.

Ideally, capacity and energy charges should be both equitable and effective in encouraging efficient resource use. An alternative to recovering all power costs from either a capacity or an energy charge would be to recover a portion of total power costs through a demand charge with the remainder being recovered from an energy charge. At first glance, it may seem most equitable to recover costs for each service component in proportion to the amount of total cost which is associated with providing that component. Rates for each unit of capacity or energy would thereby be based on the anticipated average cost of providing these service components during a given time period.

A major drawback for BPA in developing energy and capacity rates based on average costs is that the relationship between energy and capacity costs is undergoing considerable change -- change which is expected to increase in significance in the next five years. Although power costs are currently nearly equally divided between capacity and energy, the incremental cost of energy (the cost of adding new energy resources) is increasing faster than the incremental cost of capacity. Rate design based only on results of average cost analysis would fail to provide a price signal which would encourage customers to develop consumption patterns consistent with efficient resource development. Rates based on an average cost design would encourage energy consumption in excess of that consistent with an optimally efficient allocation of power resources.

As previously discussed (see Chapter III, Section F.1.), long-run incremental cost (LRIC) rates would provide the consumer with a price signal which reflects the cost to society of producing or not producing additional kilowatts and kilowatthours. Unadjusted long-run incremental cost pricing for BPA would produce revenues in excess of the revenues BPA requires. Though the excess revenue creates a problem, the economic efficiency aspects of long-run incremental cost pricing warrant further consideration of the approach.

A modification of the LRIC pricing approach would be to adjust the rate to generate only that amount of revenue sufficient to meet BPA's revenue requirement. The adjustment would require that the capacity and energy cost components be adjusted downward or constrained in a fashion that would not distort demand patterns. This would result in capacity and energy rates which would recover BPA's revenue requirement in proportion to the long-run incremental cost of each of the power components. In so doing, BPA could communicate a price signal to its customers which would make them aware of the relative costs involved in producing additional increments of specific components of service.

Results of BPA's study of the long-run incremental costs of energy and of capacity indicate that the incremental cost of capacity is $4.96 per kilowatt per month and that the cost of energy is 26.7 mills per kilowatthour. Based on data from Bonneville's cost-of-service analysis, BPA's existing average cost of capacity is $2.44 per kilowatt per month and the comparable cost for energy is 3.1 mills per kilowatthour. Thus, if BPA were to base energy and capacity rates on an average cost design, it would succeed in recovering 49 percent of the marginal cost of capacity and only 12 percent of the marginal cost of energy. Based on estimates of the anticipated sales of capacity and energy by Bonneville it would be possible to establish capacity and energy rates which would recover revenues sufficient to meet, but not exceed, repayment requirements while recovering equal percentages of the marginal costs of capacity and energy. This constrained marginal cost approach would convey an appropriate price signal to customers regarding the relative marginal costs of capacity and energy, since they would be priced proportionate to their marginal cost, even though it would fail to reflect the full marginal cost of either service.

Table VI-1 displays the effect which various methods of dividing cost recovery between energy and capacity would have on the rates charged for those service components and on the proportion of firm power revenues derived under each charge, given the condition that, with the exception of the LRIC alternative, the rates would approximately recover BPA's revenue requirement.

TABLE VI-1

Effect of Cost Recovery Methods on Rates for Demand and Energy

Cost Recovery Method	Required Rate Energy (Mills/kWh)	Required Rate Demand (Dollars/kW/Month)	Percent Revenues Derived Capacity Charge	Percent Revenues Derived Energy Charge
Recovery of All Costs through Demand Charge	0	3.98	100	0
Average Cost	3.1	2.44	57	43
Constrained Marginal Cost	5.1	0.95	24	76
Recovery of All Costs through Energy Charge	8.0	0	0	100
Rate Based on Long Run Incremental Cost	26.7	4.96	24	76

An average cost rate design would result in higher rates for capacity and lower rates for energy than a constrained marginal cost design. The highest rates for either capacity or energy would occur if rates were based on the long-run incremental cost of each component.

The effect of variations in the distribution of revenues between energy and capacity on the wholesale power costs of BPA's customers would depend on the customers' load factors. Customers with higher than average load factors would benefit from rates which collect a relatively greater proportion of costs under the capacity rate whereas a recovery method which results in an increase in energy rates would favor low load factor customers.

Table VI-2 illustrates the effect which the various pricing methods would have on the average cost per kilowatthour of power being taken under several different load factors. In all cases, except that based on long-run incremental cost, rates are adjusted to produce BPA's revenue requirement given anticipated sales of energy and capacity during calendar year 1980.

TABLE VI-2

Effect of Cost Recovery Methods on
Average Cost[1] Per Kilowatthour (mills) of
Power Delivered at Different Load Factors

Cost Recovery Method	Load Factor (Percent)				
	50	70	85	95	100
Recovery of All Costs from Demand Charge	10.90	7.79	6.42	5.74	5.45
Average Costs	9.78	7.87	7.03	6.62	6.44
Constrained Marginal Costs	7.70	6.96	6.63	6.47	6.40
Recovery of All Costs from Energy Charge	8.00	8.00	8.00	8.00	8.00
Rate Based on Long Run Incremental Costs	40.29	36.41	34.69	33.85	33.49

1/ With exception of the LRIC case, this represents the average revenue which would be required by BPA to meet its revenue requirement.

b. Application of the Design Concept in BPA's Existing and Proposed Rates. Both Bonneville's existing power rates and its proposed rates have separate charges for capacity and energy. The existing rates for capacity and energy are not based on a fully allocated cost-of-service study such as that performed by Bonneville in developing its proposed rates. In the past the primary concern in developing energy and capacity charges was to insure adequate revenues. Detailed analysis of cost classification to energy versus capacity was not undertaken. Under BPA's existing rates approximately 54 percent of firm power revenues in 1980 would come from capacity charges with approximately 46 percent attributable to energy charges. This is very close to the revenue distribution which would occur under average cost rates as shown in Table VI-1.

Bonneville's proposed rates for firm and industrial firm power represent a significant shift in the revenue burden from the capacity rate to the energy rate. Under the proposed rates, 40 percent of 1980 firm power revenues would derive from capacity charges with energy charges accounting for 60 percent of the total. The proposed rates were based on average costs for capacity and energy derived from BPA's cost-of-service analysis, but were then modified to reflect the results of Bonneville's long-run incremental cost study. The modification consisted of lowering the secondary peak period capacity charge and eliminating firm power capacity charges during night-time hours. The resulting decrease in revenues would be offset by revenues derived from sales of nonfirm energy and from revenues in excess of costs for firm capacity sales.

Thus, the proposed rates do not communicate a complete price signal to power users concerning the relative incremental costs of capacity and energy; however, a one step shift to a constrained marginal cost rate would not meet the objectives of stability and continuity of rates. Furthermore, further research is required to develop the most appropriate method for applying marginal cost principles to BPA's rates and also regarding the adequacy of the measurement techniques upon which the parameters of such a rate would depend. Acceptance of and confidence in constrained marginal cost adjustment techniques require additional study given state-of-the-art limitations. The proposed rates are, however, a reasonable first step in alerting power consumers to the increasing costs of energy production.

2. Time Differentiation of Rates.

a. Discussion of the Design Concept. Time differentiated pricing is based on the concept of cost causation. In the short run, demand for power is met from existing capacity, if it is available. In the long run, additional energy and capacity may be needed to meet increased energy and peakload demand. Because additional energy and capacity may be required during peak periods, the costs of supplying that energy and capacity may be higher than during off-peak periods.

The goal of time-differentiated pricing is to develop correspondence between power rates and variations between time periods in the cost of power production. The time periods to which the rate differentials apply may include entire seasons of the year or may be limited to certain periods of the day. The terms "seasonal rates" and "time-of-day rates" will be used in refering to these types of time-differentiated pricing.

There are practical limitations to the use of time-differentiated pricing due to the complexity involved in administering a time-differentiated rate. The time periods used should be limited to a feasible number and time periods with similar costs should be combined. Also, there must be some way of metering power consumption by time period. If rates are differentiated on a seasonal basis only, the metering problem is minimized. However, if time-of-day rates are employed, meters must be capable of distinguishing between time periods in recording consumption. With a few exceptions, Bonneville's existing meters are capable of recording the data required for application of both seasonal and daily rate differentials.

Theoretically, time-differentiation of rates could be based on either the average cost of providing power during a given period or the marginal cost of such production. Bonneville has prepared studies of both the average and long-run incremental costs of its power production during specific pricing periods.

An alternative to either average cost or marginal cost based time-differentials would be to develop rates on a constrained marginal cost basis.

An additional design alternative would be to simply eliminate time differentiation from rates, charging equal rates throughout the year for energy and capacity regardless of when consumption occurs. This approach would be consistent with the time-differentiated LRIC study results for energy, but would conflict with the results for demand.

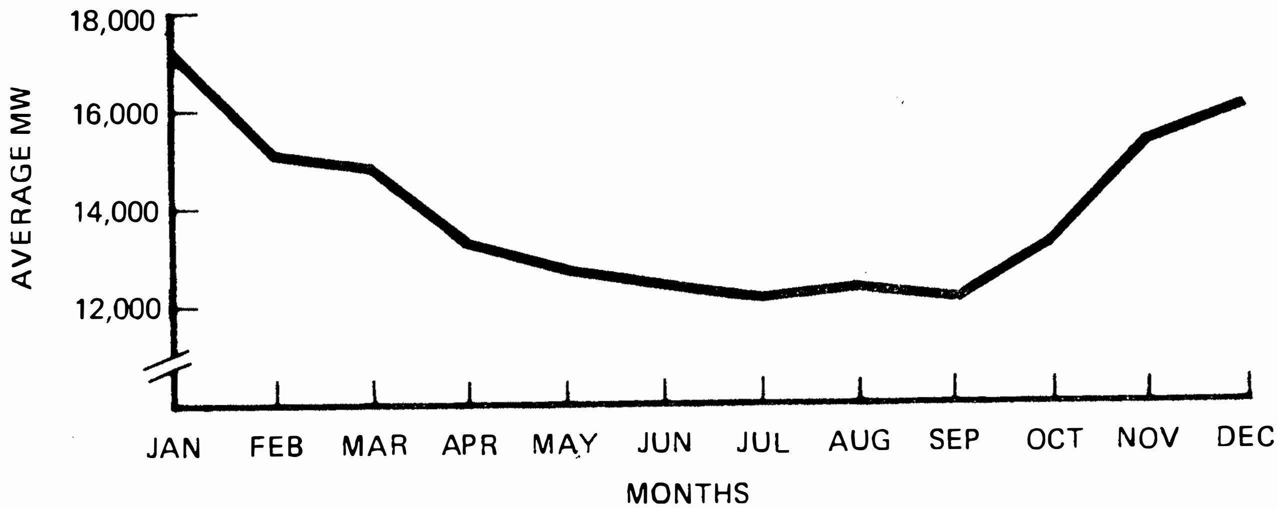
(1) Survey of Research on Time-Differentiated Pricing. There is some evidence that loads can shift from the peak season to the off-peak season in response to a seasonal rate differential. In France, seasonal pricing has been associated with the fact that average winter peak loads as a proportion of summer off-peak loads fell from 2 to 1.6 (NERA, 1977a, p. xii). A study of the Salt River Project credits the adoption of seasonal rates in 1962 with arresting the steady decline in annual load factor that region experienced prior to that time and stabilizing it at about 55 percent (Perkins, 1975, p. 168). Finally, a computer simulation model for the U.S. developed by the firm of Temple, Barker, and Sloane (1976) indicated a larger seasonal rate differential can result in a significant improvement in the annual load factor, reducing the peak demand by almost 9 percent.

It is, however, unlikely that a significant change in the annual load factor could be experienced in the West Group area. The load factor is already higher than the areas analyzed in the above studies, and an informal survey of the few Pacific Northwest utilities which do have seasonal rate differentials has not revealed a significant response. However, seasonal rates in the Pacific Northwest have not been in effect for long and the differentials are often not very large.

There is a great deal of controversy regarding the effect of time-of-day rates on peak demand. Many studies have been made of the European experience with rates of this type (e.g., Laaspere, 1975; Nissel, 1976b; Hughes, 1975; Mitchell and Acton, 1977). Most have discovered significant consumer response to time-of-day price signals. Others, however, assert that price effects are insignificant when compared to the effects of direct load controls

Figure VI-1

SEASONAL LOAD PATTERN, WEST GROUP AREA 1977



and promotion of off-peak use by the European utilities (Nissel, 1976a). Figure VI-2 shows the long term improvements in daily load factor experienced in France and Britain.

Many experiments with time-of-day pricing have been initiated in the U.S. over the last several years (for an excellent survey of the studies, see CERCDC, 1977, Appendix B). Several different rates have been tested in varying situations. The rates have been applied to both summer and winter peaking utilities, with varying peak hours and with different ratios of peak to off-peak rates (FEA, 1977, Appendix C; ERA, 1977, Table 1; CERCDC, 1977, Appendix B). It is very difficult to generalize from this wide variety of tests, but the Economic Regulatory Administration (1977, p. 2) summarized the findings in this manner:

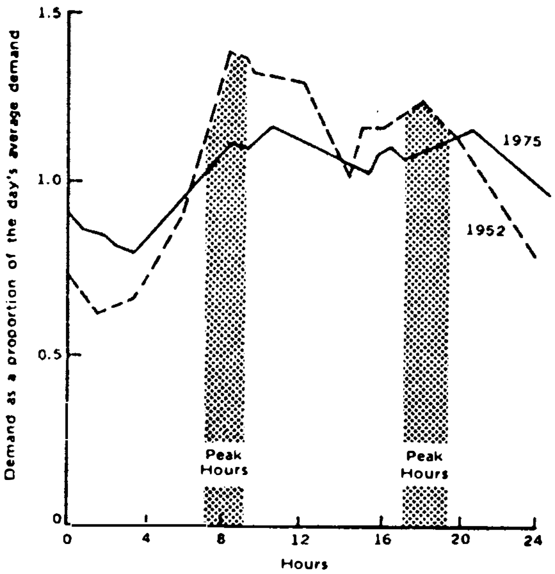
> ". customers have uniformly been found to respond significantly to changes in electricity prices at all hours of the day, including peak periods;
>
> . peak period price elasticity (i.e. 'responsiveness') appears to exceed off-peak elasticity;
>
> . time-of-use rates will reduce residential customer peak demands even on the hottest day of the year;
>
> . customer attitudes toward time-of-use rates are decidedly positive."

Other studies do not support some of these statements. For example, NERA (1976b, p. 37) and J. W. Wilson and Associates (1977, p. 64), in reports for the Electric Utility Rate Design Study, both concluded that the peak period elasticity was lower than the off-peak elasticity. However, as Uhler (1977, p. 91) pointed out, "lower" does not mean zero, and all the tests appeared to indicate that time-of-use rates reduced peak consumption and increased off-peak use. In another study, Romano and Elliott (1977, p. iv) discovered that the particular rate form adopted could have a large effect on customer acceptance. A time-of-day demand charge for the residential sector met much resistance at Green Mountain Power Corporation in Vermont, while a time-of-day rate form which charged only for kilowatthours was accepted virtually unanimously.

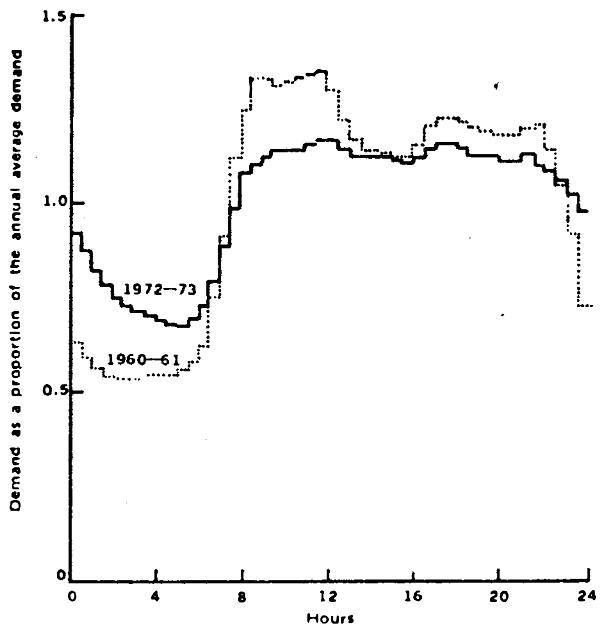
In attempting to apply these findings to the Pacific Northwest power supply system, several factors should be considered. First, different utilities have different cost structures and each utility should conduct studies to determine the cost effectiveness of peakload pricing for its own system and compare it with alternative methods of load management (Uhler, 1977, p.2). Second, no time-of-day rate experiments have been initiated in the Pacific Northwest, and it is not known whether results from other regions could be applied here. The very high per capita consumption of

FIGURE VI-2

COMPARATIVE FRENCH AND
BRITISH SYSTEM LOAD CURVES



FRENCH DAILY LOAD CURVES FOR
REPRESENTATIVE JANUARY WORKDAYS,
1952 AND 1975



BRITISH DAILY LOAD CURVES
ANNUAL AVERAGES, 1960–61 AND 1972–73

SOURCE: Bridger M. Mitchel and Jan Paul Acton "Peak Load Pricing in Selected European Electric Utilities". In Anthony Lawrence (ed.), Forecasting and Modeling Time-of-Day and Seasonal Electricity Demands. Palo Alto: Electric Power Research Institute, December 1977, pp 3—36. Reprinted by permission.

electricity and the relatively low rates are regional characteristics which may affect the direct application of results.

In the Pacific Northwest, residential loads are the prime cause of utility peaks (see Figure VI-3). Space heating is by far the most significant component of the residential peak. Peak use of lighting, small appliances, water heaters, and electric ranges also approximately coincides with the peak space heating periods (Temple, Barker, and Sloan, Inc., 1976, pp. III-8 thru III-14).

In several utilities, time-of-day pricing has been successful as a means of flattening these residential peaks in an effort to minimize capacity requirements (e.g., Burbank 1977; Romano and Elliott, 1977; Atkinson, 1977).

If time-of-day pricing were adopted at the retail level, some additional effects on household expenditures would be anticipated. Those persons unable to avoid heavy electrical use during peak hours would be affected most adversely. Research by Hendricks, et. al., (1977, p. 149) indicates that income level bears relatively little relationship to time of use. This research involved a summer peaking utility, however, and the results might be somewhat different for winter peaking utilities since home heating in colder areas may be considered more essential, and therefore less sensitive to electricity costs, than air conditioning in warm locations.

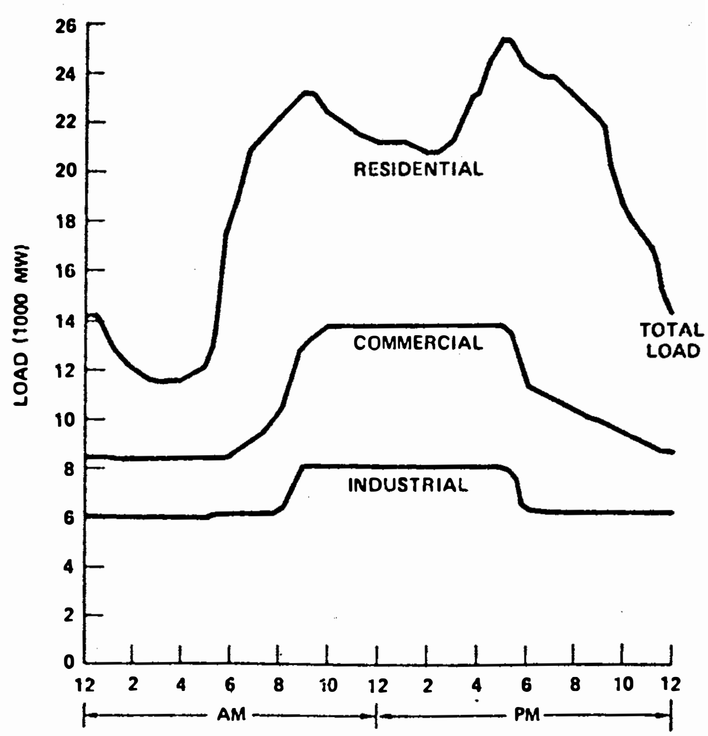
Space heating and air conditioning represents a larger proportion of the energy budget for lower income consumers, and space heating needs are difficult to move off peak, barring major investments in heat storage facilities. The lower income consumer may therefore experience a greater proportionate increase in his electrical costs than the upper income family.

Also, the appliance inventories of middle and upper income consumers are larger and more varied than those of the poor and this improves the potential of the former for benefiting from time-of-use rates. Although it may be a simple matter for someone to load a dishwasher and then delay turning it on until bedtime, it is much more inconvenient to be hand washing dishes at midnight. Also, the family possessing a larger number of appliances would be better able to condense the time required to perform a variety of tasks into limited off-peak hours.

Although an upper income family may appear to be in a better position than a poor family to take advantage of time-of-day pricing, it nevertheless has less incentive to do so. The poor may be more willing to suffer the inconvenience of shifting off peak in response to the monetary consequences involved. This could perhaps be viewed as a benefit for the poor.

FIGURE VI-3

APPROXIMATE PACIFIC NORTHWEST
ELECTRICAL LOAD (PEAK DAY)



Source: Myers, et al., 1976, P.12

It has been indicated that among a group of Missouri utility customers the lowest 50 percent (classified by income levels) accounted for 24 percent of electricity demand both on and off peak (Lockeretz, 1975, p. 153). This coincides with the conclusion that scheduling flexibility rather than current patterns of use would be the primary determinant of variation in the impact of time-of-day pricing across income categories. In other words, since the consumption patterns of all income groups are similar with respect to the proportion of consumption occurring during specific time periods, time-of-day pricing would affect all consumers in a similar manner, given that no changes are made in current consumption patterns. However, the extent to which the consumer could alter the time at which he uses electricity could alter the impact of such rates. If lower income groups experience greater difficulty in adjusting use to time-of-day pricing, they will experience a greater degree of adverse financial impact than will other groups.

In addition to affecting the time at which residential customers consume electricity, time-of-day rates could encourage certain types of commercial and industrial consumers to alter their operating schedules. In order to take advantage of lower nighttime rates, some firms might create or expand the use of "graveyard" shifts. The Wisconsin Public Service Commission asserted that time-of-day rates would serve as an attraction to firms capable of shifting their consumption of power to off-peak hours (NARUC Bulletin, Aug. 29, 1977, pp. 19-20), while a public utility commissioner from Connecticut has expressed a "certainty" that time-of-day rates "will inhibit new investment in certain of those industries which are the lifeblood of regional economic development" (Standish, 1976, p. 188). It could be that both statements are right, with time-of-day rates being advantageous to some types of industries and disadvantageous to other types.

The effects of increased use of nighttime workers would be experienced primarily by the workers themselves. At present, approximately 4 to 5 percent of the domestic work force is engaged in nighttime shift work. Studies of the effects of shift work indicate that such employment schedules can interfere with homelife, social contacts, and even the physical well-being of some persons (see CERCDC, 1978, pp. IV-59 to IV-65). Most workers dislike shift schedules and many complain of nervousness, insomnia, decreased work efficiency, and gastrointestinal distrubances. Aberstedt (CERCDC, 1978, p. IV-64) estimates on the basis of his research into shift work that approximately 20 percent of all employees would be unable to adapt to a shift schedule.

Although most shift workers raise objections to their schedules, some prefer nighttime work because it allows them an opportunity to obtain second jobs or improves their ability to conduct personal business during regular business hours or engage in recreation during periods when recreational facilities are less crowded. Also, shift workers generally receive about 4 percent higher wages than their daytime counterparts.

The California Public Utilities Commission has ordered the three largest investor-owned utilities to develop specific rate schedules which would enhance cogeneration. It noted that "rates for standby service are a deterrent to cogeneration in that they are viewed as punitive" (CPUC, 1978, p. 3). Time-of-day rates, on the other hand, are well suited to the needs of industries which have cogeneration.

Experience in Europe has shown that industries with cogeneration have been able to benefit from time-of-day rates (Londwatt Consultants, 1978, pp. I-22, I-23). By providing proper pricing signals, time-of-day rates should assist in assuring that cogeneration projects will be designed to provide firm power during utility peak load periods.

In the Northwest, the industrial sector load varies relatively little throughout the day, although it does contribute to the utility system peak (see Figure VI-3). An important issue in considering the potential impact of time-of-use rates is the degree to which industry can be expected to respond to a new rate structure by shifting load from the peak period to the off-peak. Much research has been conducted on the potential for peakload shifting, with a good deal of it concerning the European experience with time-of-day pricing. A recent study by the Rand Corporation (Mitchell, Manning, and Acton, 1977) has found that several industries have exhibited strong responses to time-of-day or interruptible rates: cement, ferroalloys, electrometallurgy, petroleum refining, glass, brick, iron, and steel. The Rand report concluded that a peakload pricing structure adopted in California would be able to save from 33 to 46 percent of the entire peak demand (p. vi). In Britain, it is reported that large industrial users consume approximately 25 percent less power during the peak period than they do off-peak (FEA, 1977, p. 69).

Other studies have disputed these interpretations of the European experience. A NERA study (1977 a, pp. 30-32) has indicated that the British Central Electricity Generating Board attributes minimal peak savings to the industrial sector. Londwatt Consultants (1978) has prepared an extensive rebuttal of the conclusions drawn in the Rand report. One particularly important point they made was that the industries which showed the most responsiveness to peakload pricing were those with the most in-house power generation; many industries were not altering production patterns, but were simply switching to their own generation during utility peak periods. And Nissel (1976a, p. 25) contends that peakload price signals are far less likely to produce desired improvements in load factor than are direct load controls.

The experience with time-of-day rates in the United States is not as extensive as in Europe, but there are, nevertheless, important indications of the potential response to such rates. Consumers Power Company in Michigan has had time-of-day rates for its large commercial and industrial customers for many years, with peak rates almost five times as high as the off-peak rates. An official of that utility has reported that of the 1600 customers on such rates, only 11 consciously operate their plants to shift some of their loads to off-peak periods. Those 11 industries (7 foundry operations with electric furnaces, 3 cement plants, and 1 chemical plant) were able to save 6.3 percent of the utility's potential peak demand (Jefferson, 1977, pp. 119-120). The Public Service Company of New Mexico has time-of-day rates that apply only to three large customers, but their response has been credited with boosting the utility's annual load factor by 6 percent (Electrical Week, Jan. 31, 1977, p. 9).

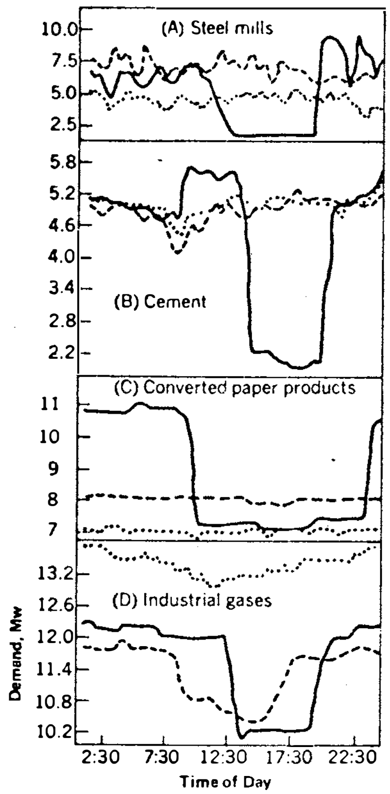
A rate design experiment at Pacific Gas & Electric in California has also provided information about the response of industrial and commercial customers (CERCDC, 1977, pp. 56-60; Gorzelnik, 1978, pp. 64-65). As indicated in Figure VI-4, several industrial customers with large loads were able to make dramatic shifts in their operations. However, many customers (including most customers in the commercial class) could not shift load from the peak to the off-peak period, and they responded by shifting their whole load curves downward by pursuing energy conservation (Figure VI-5). Finally, it was discovered that responses could vary significantly among identical operations, making prediction about potential responses extremely difficult (Figure VI-6).

Applying these experiences to the Pacific Northwest is very difficult. That certain industries can respond to time-of-use rates by shifting peak load to off-peak seems clear, but the magnitude of such a potential depends on many variables. Although a technical study by Arthur D. Little, Inc., concluded that there are few highly energy-consuming industries that would respond significantly to time-of-use rates (1977, p. iv), the industries themselves have indicated a willingness to shift some loads under such rates (e.g., Sherry, 1976, p. 1186; Ontario Hydro, 1976, Vol. XA, p. 5; and Lavidge, Inc., 1977, p. 14-7). Much depends on the rate differential between peak and off-peak rates; a survey in Michigan indicated the differential would have to be at least two-to-one to cause significant changes in customer usage patterns (Electric Light and Power, Sept. 1976, p. 18). Other economic and technical constraints which affect the potential response include labor costs and unions, type of production, the existing load curve, and the size of the firm.

Nevertheless, the direct-service industries in the Northwest are not expected to respond to seasonal or time-of-day rates. Generally they have extremely high load factors, usually operating 24 hours a day all year through, and are not able to shift load from the peak period to off-peak periods.

FIGURE VI-4

Selected Industrial Response to Time of Use Rates, Pacific Gas & Electric Company



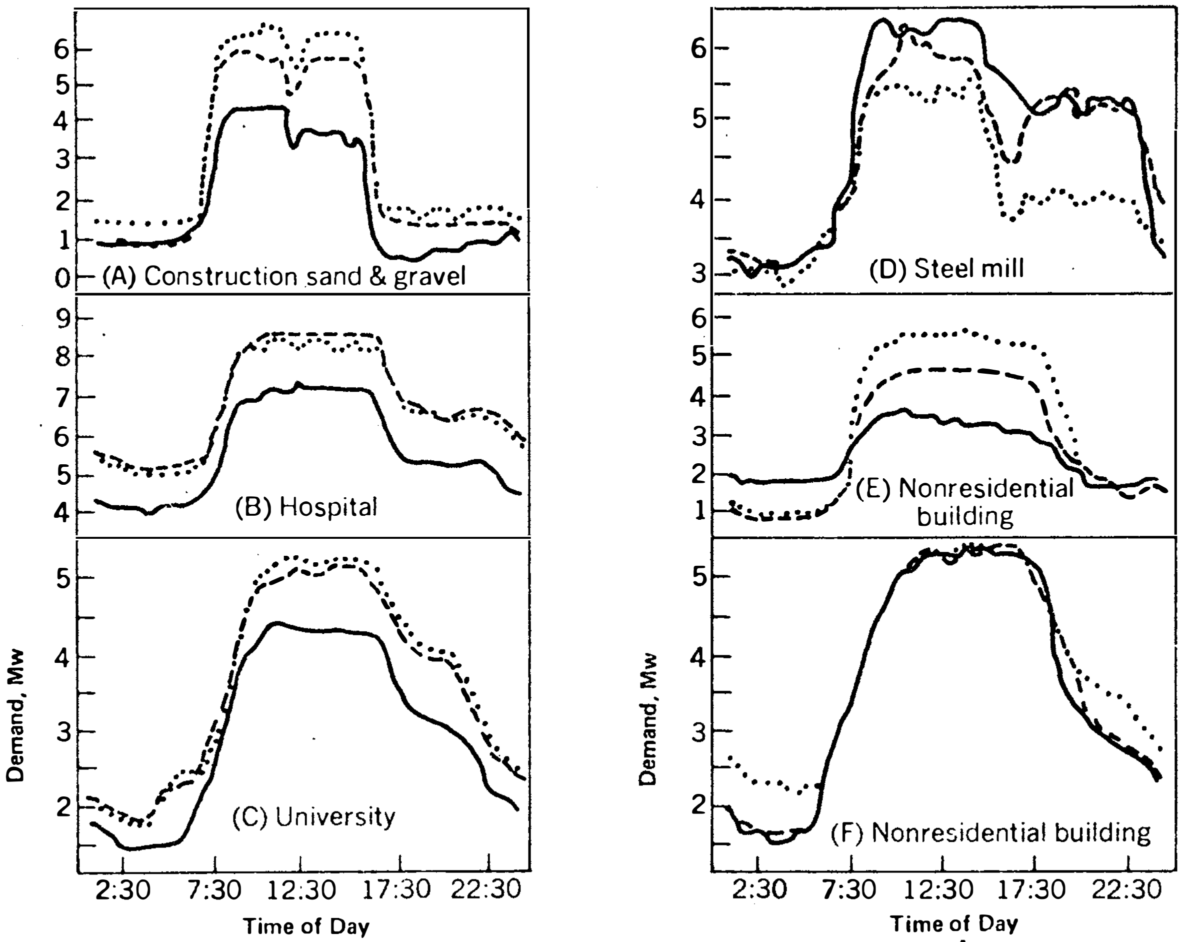
Change in Load Patterns

—— May 1977 — — May 1976 ---- May 1975

SOURCE: California Energy Resources Conservation and Development Commission, California Load Management Research 1977, Sacramento, October 1977, p. 58

FIGURE VI-5

Selected Industrial and Commercial Response to Time-of-Use Rates, Pacific Gas & Electric Company



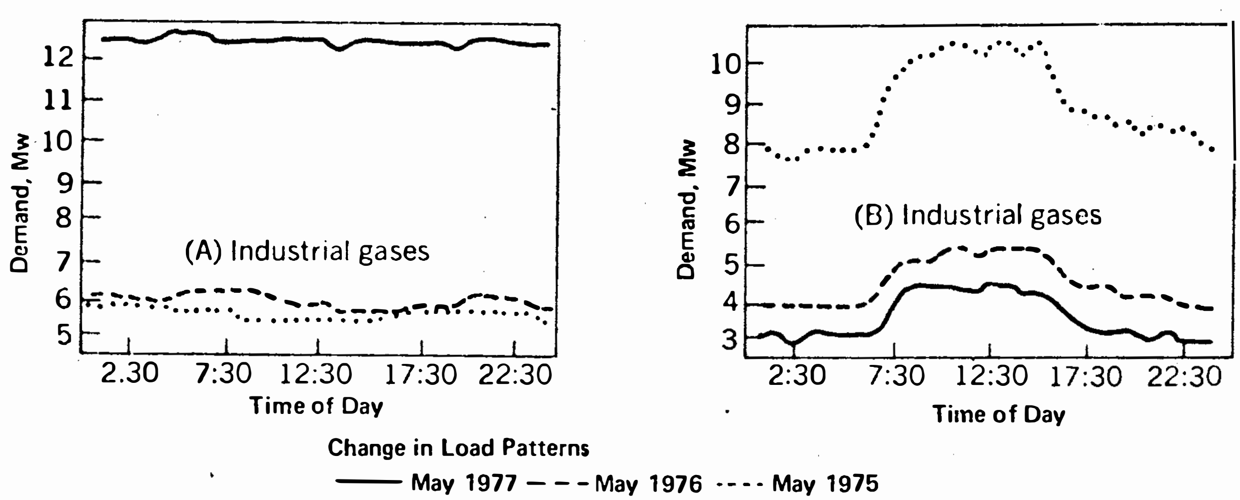
Change in Load Patterns

—— May 1977 – – – May 1976 ····· May 1975

SOURCE: California Energy Resources Conservation and Development Commission, California Load Management Research 1977, Sacramento, October 1977, p. 59

FIGURE VI-6

Load Pattern Differences in Identical SIC Code Industries



SOURCE: California Energy Resources Conservation and Development Commission, California Load Management Research 1977, Sacramento, October 1977, p. 59

(2) Potential Effects of Time-Differentiated Rates on Power Operations. To assess the effects of time-of-day rates (or other load management techniques) on power operations, it is useful to examine how the generation system is planned to meet the loads. The solid line on Figure VI-7 presents a simulation of the peak week in January 1989, using a computer model of the West Group Area hydroelectric system which extrapolated the January 1972 system load shape. The area load factor for the week (the ratio of average load to peak load) is 78 percent, and the minimum load is 54 percent of the peak load, a typical load shape for the winter in the Pacific Northwest.

A report by an interutility committee on thermal plant operating characteristics (PNUCC Task Force 8, 1977) has indicated that the planned generation system indicated by the solid line on Figure VI-7 will not be able to meet the forecasted area load on an hourly basis. Some of the problems identified by the report were excessive daily load swings, insufficient water and regulation capability to carry sustained peaking, and intolerable fluctuations in pool tailwater levels. An important question, then, is how time-of-day rates adopted at the retail level could alleviate these problems.

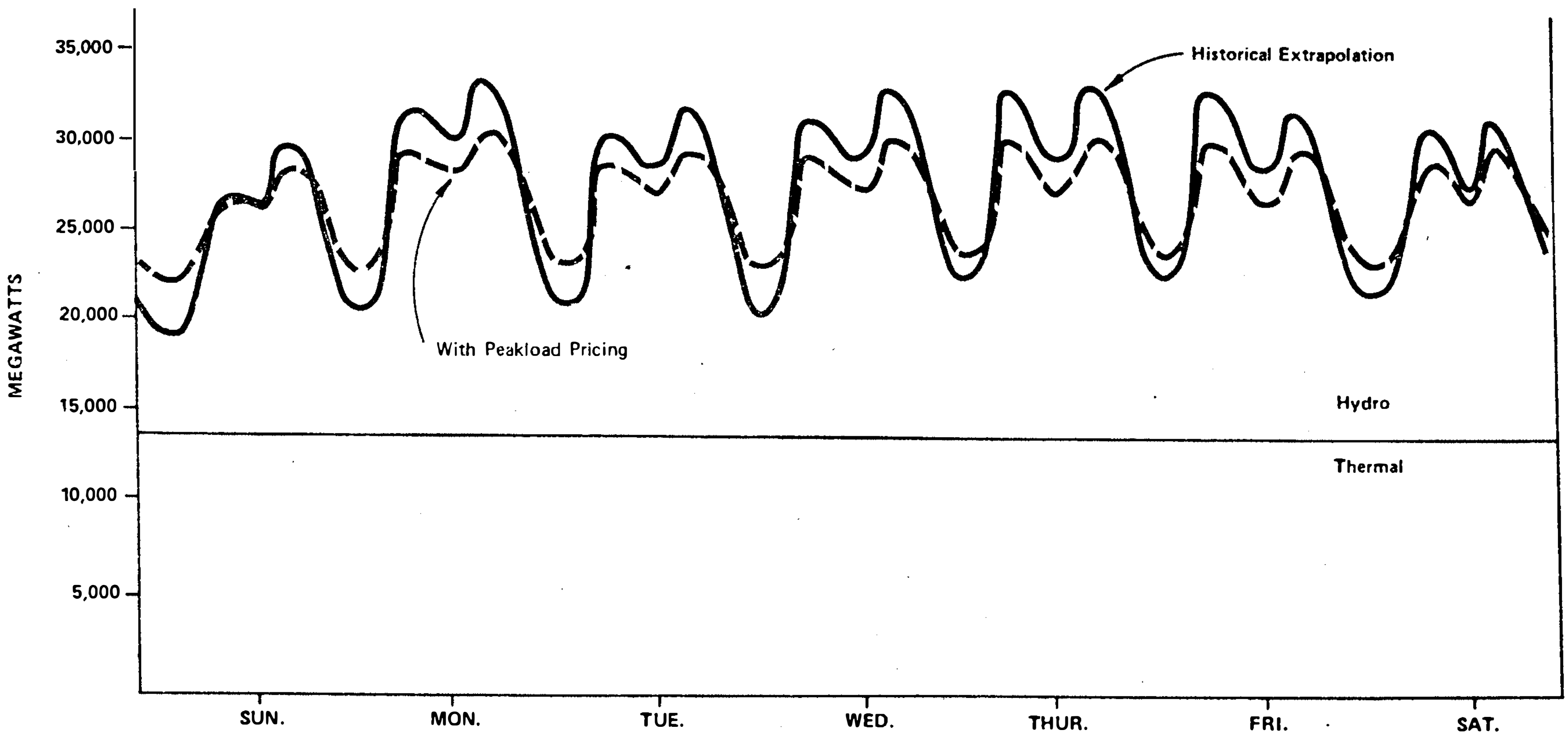
It is not possible to predict the effects of the adoption of time-of-day rates at the retail level with certainty. Nevertheless, as indicated in Figure VI-7, BPA estimates that through use of time-of-day rates it would be possible for the January 1989 peak load to be reduced from 33,500 MW to 30,500 MW. The area load factor would be thus increased to 85 percent, and the minimum load would be raised to 69 percent of the peak load. Such an improvement is well within the possible residential, commercial, and industrial response. Support for such a load shift also comes from the European experience illustrated in Figure VI-2, p. VI-23, as well as from several of the U.S. experiments (cf. Burbank, 1977, pp. 1-16; FEA, 1977, Appendix C; CERCDC, 1977, p. 58).

The projected results are plotted on Figure VI-7 as the dashed line entitled "with peakload pricing." The most significant effect is, of course, on the hydro system, which would experience a large decrease in fluctuations. The difference between the hydro maximum and minimum load for the week is 15,100 MW for the historical extrapolation and 8,800 MW for the load management case. In both cases the thermal operation is uniform for the week.

From a theoretical standpoint, a given degree of peakload pricing should have a lasting and consistent effect on the distribution of loads between peak and off-peak periods, assuming other relevant factors are held constant. Practically speaking, however, it is anticipated that the composition of future Pacific Northwest load growth will gradually counteract the effects of any one-time peakload pricing measure. The reason for this is that the

Figure VI-7

JANUARY 1989 PEAK WEEK LOAD CURVE SIMULATION,
HISTORICAL EXTRAPOLATION VS. PEAKLOAD PRICING



SOURCE: Bonneville Power Administration, Division of Power Management, April 1978 industrial sector, with its typically high load factor, is expected to comprise a much smaller proportion of future load growth than is represented by its current share of regional electrical use. The comparatively low load factor residential sector is expected to represent an even greater proportion of future load growth. The combined effects of these changes would result in a lowering of load factor. Nevertheless, the decline in future load factor would continue to be partially offset by the existence of peakload pricing. Furthermore, careful application of time-differentiated rates, through gradually increasing the peak/off-peak price differential, could conceivably counterbalance the effects of changes in the composition of regional loads, thereby stabilizing the system's load factor.

(3) Potential Environmental Impact on the Hydro System. Time-of-day pricing could have important effects on the daily load shape of the Federal generation system. In order to gauge the potential environmental impacts of time-of-day pricing, two computer simulations of hourly hydroelectric plant operations were produced. Because peaking and load-following requirements of Pacific Northwest utilities are generally met by hydroelectric plants and because load changes directly affect such requirements, load factor improvements would have a direct effect on the operations of hydroelectric plants. A complex computer program was used to study hourly resource operations. By simulating operation of hydro plants to meet loads that follow historical patterns as well as loads altered by peakload pricing, it was possible to obtain incremental effects of such pricing on each of 35 individual plants.

Two times of year were studied. First, hourly simulations with and without peakload pricing during a typical, heavy load week in January 1989 were made. In January, peaking requirements are largest while streamflows and reservior levels are relatively low and operations at hydro plants are most demanding. Also, because loads are highest in January, the maximum effect of the assumed load factor improvement is observed. Second, hourly simulations for a typical week in October 1989 were made. Peak loads are lower in October than in Jaunary, and more water is typically available in October to operate the hydro plants. But October is interesting because it is the month in which the West Group monthly load factor is at a minimum - about 73 percent. Thus, the October studies describe a case where time-of-day pricing effects are moderate while peaking operations involve extreme generation fluctuations.

The simulations showed that in both the Janaury and October cases most of the 35 hydro plants reacted as expected to load changes. The hydro plants responded to the load management assumption, collectively and individually, by operating at increased load factors and reduced maximum generation levels. Translated into operational terms, minimum outflows increased, maximum outflows decreased, tailwater fluctuations decreased, and minimum tailwater elevations increased. Figure VI-8 shows the incremental effect of peakload pricing on tailwater elevation and outflow patterns at Grand Coulee and Priest Rapids. The type and degree of load management effects on most of the 35 plants studied were similar to the effects on Grand Coulee and Priest Rapids. The remaining plants show little or no operational effects from load factor improvements. A few other plants were largely unaffected because of extremely tight nonpower constraints dictating specific operations regardless of load.

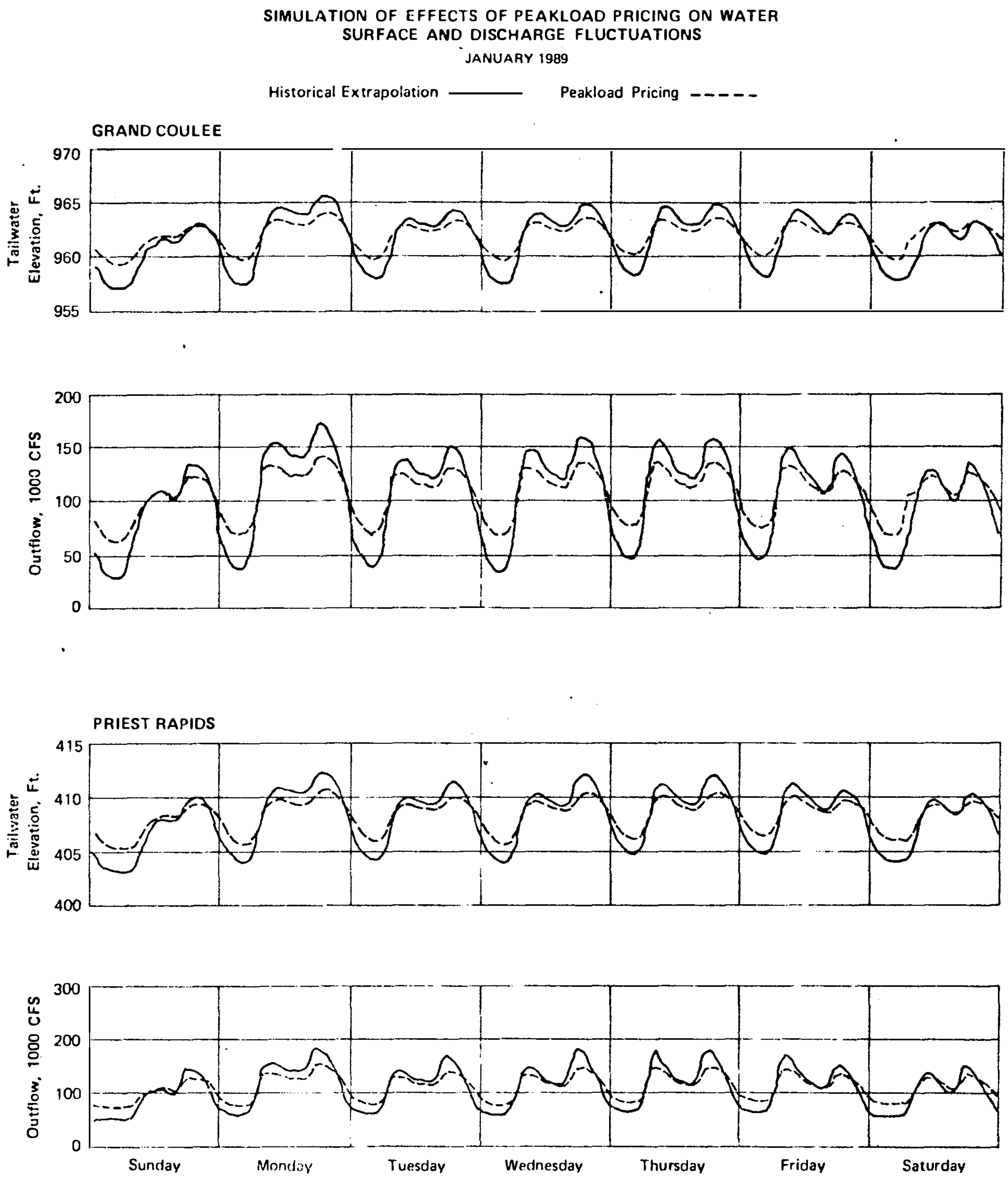
Figure VI-8 reveals that time-of-day pricing decreased hourly, daily, and weekly tailwater surface fluctuations at all affected plants in both January and October. Largest reductions were noted in January; maximum hourly and daily fluctuations were reduced about 40 percent and maximum weekly fluctuations were reduced 40 to 50 percent at most plants. In October, reductions in hourly, daily, and weekly surface fluctuations were all about 30 percent. On an absolute scale most plants realized a reduction in maximum tailwater fluctuations of approximately 2-1/2 feet per day in January and 1 foot per day in October.

All affected plants realized increased minimum tailwater surface elevations in both January and October. These increases amounted to about 1 foot at many plants in January, but only about 2/10 foot in October. With peakload pricing, hydro plants will generate at higher levels at night and on weekends, resulting in higher minimum outflows and, consequently, higher minimum tailwater surface elevations. This effect is especially noticeable at major hydro plants situated above free flowing reaches, such as Hells Canyon, Priest Rapids, and Bonneville. At Priest Rapids and Hells Canyon, minimum tailwater surface elevations increased by over 2 feet in January. The effect at Bonneville was somewhat less, due primarily to tight constraints imposed on its operation by the Army Corps of Engineers.

Because of increased minimum generation levels (at night and on weekends) associated with peakload pricing, minimum outflow rates also increase. In January minimum outflow increased substantially (more than 30 percent) at nearly every plant. This effect was most pronounced at the mid-Columbia plants. In the October case, a system-wide increase of about 10 percent resulted.

Water surface fluctuations prevent the establishment of stable biological communities and are generally considered to be detrimental to most forms of aquatic life, especially to those organisms that must pass one or more of their life stages in the shallow water zone. Many insects, amphibians, and fish, as well as some birds and mammals, are in this category. Any hydro operation which diminishes the zone of surface fluctuation would be generally beneficial to biological productivity.

FIGURE VI-8


SIMULATION OF EFFECTS OF PEAKLOAD PRICING ON WATER
SURFACE AND DISCHARGE FLUCTUATIONS
JANUARY 1989
Historical Extrapolation
Peakload Pricing
GRAND COULEE
Tailwater Elevation, Ft.
970
965
960
955
Outflow, 1000 CFS
200
150
100
50
0
PRIEST RAPIDS
Tailwater Elevation, Ft.
415
410
405
400
Outflow, 1000 CFS
300
200
100
0
Sunday
Monday
Tuesday
Wednesday
Thursday
Friday
Saturday

Of particular concern in the Columbia River Basin is the welfare of anadromous fish, primarily salmon and steelhead. Few natural spawning areas for salmon and steelhead remain in the system below Chief Joseph Dam on the Columbia River. The value of those spawning grounds which remain is often diminished by water fluctuations associated with peaking operations. One notable example is the fall Chinook salmon spawning bars located below Priest Rapids Dam on the Columbia River.

Chinook salmon spawn on these bars in October and November. In this 43-mile wide reach of free flowing river, an average of 2,795 nests are constructed. The amount of area available to them for nest construction, i.e., the amount of bar submerged, and the eventual success of spawning attempts is affected by prevailing operational activities at Priest Rapids (Sandison, 1977). As indicated in Figure VI-8, time-of-day pricing could result in an increase in tailwater elevation below Priest Rapids of over 2 feet during the spawning to be successfully utilized. Any load management program that reduces the amplitude of the fluctuation zone or increases the minimum flow, and, therefore, the minimum tailwater elevation, enhances the survival chances of eggs and larvae and benefits the species.

b. Application of the Design Concept in Bonneville's Existing and Proposed Rates. Bonneville's existing rate to public agency customers contains a seasonal differential in both the capacity and energy charges. The differential in the capacity charge is cost justified by the fact that hydro peaking units are being added to the system to serve winter season peak-hour capacity requirements. The seasonal energy differential is based on the assignment of hydro storage and some thermal costs exclusively to the winter period. Under Bonneville's existing rates the winter period runs from September 1 through March 31. The firm power demand rate is 13 percent greater and the energy rate is 90 percent greater during the winter season than during the summer period (April 1 through August 31).

Bonneville's proposed rates also contain a seasonal differential for firm power energy and capacity. In addition, the proposed rates feature a time-of-day differentiation for the firm power capacity rate. The proposed summer season energy rate applies to the period April 1 through August 31 whereas the summer season capacity rate is in effect from June 1 through November 31. The on-peak hours for the proposed capacity rate are 7 a.m. to 10 p.m. Monday through Saturday. The criterion of combining periods with similar costs was used to establish the time parameters of the pricing periods (BPA, 1976b).

Bonneville's proposed firm power energy rate would be 10 percent higher during the winter than during the summer. The proposed firm power demand rate during the peak period is 64 percent higher during the winter than during the summer. There would be no demand charge for capacity use during the off-peak period.

The differential in BPA's proposed firm power energy rate is based on the costs of storage associated with the hydro system. The long-run incremental cost of energy was considered to be the same for the summer period as for the winter period since thermal resources will be needed to meet load growth regardless of the period during which consumption increases. The baseload thermal plants which would be developed to accommodate this growth are designed to be operated throughout the year except for planned maintenance, refueling, and forced outages. Because outages are dependent upon many factors, including fuel life, equipment failure, demand for energy, and the availablity of alternative resources, seasonal patterns cannot be expected to occur consistently.

The time-differentiated LRIC analysis of capacity costs resulted in assignment of all capacity costs to the winter peak period. Thus, the marginal cost of capacity was assigned a value of zero during the summer period and during the off-peak hours of the winter period. The average cost time-differentiated study did result in assignment of some costs to off-peak as well as peak period hours. However, Bonneville is proposing to base the winter and summer peak period rates on the average cost time-differentiated study; but, in recognition of the results of the marginal cost based time-differentiated study, has chosen to eliminate all capacity charges during the off-peak summer and winter hours.

Bonneville received comments regarding the length of the daily peak period for capacity. It was suggested that the length of the period would reduce its effectiveness in reducing Bonneville's peak load since relatively insignificant load shifts outside the peak period would be possible due to the considerable change in time of consumption which would be required for the majority of loads occurring during the long peak period. However, BPA's peak occurs with relatively consistent intensity over an extended period of time. Any attempt to further narrow the peak period could lead to stimulating the development of a new peak just prior or subsequent to the existing peak period. Such a development would clearly be counterproductive to the goal of avoiding a shift in the peak to a period outside the existing peak period.

The impacts of time-differentiation of rates would depend on the relationship between the rate periods and the consumptive patterns of BPA's customers. Seattle, Tacoma and Chelan PUD have the ability to use their own generating resources in a manner permitting a shifting of the requirements supplied by Bonneville from peak hours to offpeak hours in response to time-of-day pricing. Also, customers whose power requirements are lower during the winter than during the summer would have lower annual costs under the existing seasonal energy differential than if there were no seasonal differential. The proposed seasonal energy differential would also lower the annual costs of such customers, though not as much as is the case with the existing differential, and would still constitute a significant benefit for these customers when compared to a flat or undifferentiated rate.

Customers most likely to benefit from a seasonal energy differential would probably be those with significant irrigation loads since the bulk of irrigation power requirements occurs during summer months.

On the other hand, the existing and proposed seasonal differentials would result in higher costs to customers with especially large portions of their load occurring during the winter period than would be the case if there were no seasonal differential. Most of the utilities in the region experience winter peaks due primarily to space heating, but about 20 preference utilities, constituting about 5 percent of the West Group Area's load, have summer peaks caused mostly by irrigation loads. Conceivably, a seasonal differential which results in lower power costs during the summer could foster electricity consumption by irrigators, although the significance of the effect would be small under the proposed differential. However, the winter period is the time during which most costs are incurred to add generation and transmission resources to the system. The proposed seasonal differential reflects those additional costs. Figure VI-1 depicts the seasonal load pattern for the West Group Area.

3. Industrial Availability Credits.

a. Discussion of the Design Concept. Bonneville currently sells power to direct-service industrial (DSI) customers under a schedule which recognizes that these loads are subject to restrictions not available under other firm power contracts. In recognition of BPA's right to restrict industrial deliveries, an availability credit is applied to industrial customers' demand charges when restrictions are made. Table VI-3 shows the relative privileges and obligations of BPA and the industries with respect to restricted or curtailed power.1/ The major issue with industrial rates is whether or not the restriction rights which BPA may exercise over this power should be reflected in a lower rate for industrial customers; and, if so, what method might result in an appropriate rate adjustment.

Several different approaches could be pursued in arriving at an amount to be returned to industrial customers as compensation for BPA's special restriction rights. One approach would be to compensate these customers for energy and capacity restrictions. Compensation for energy restrictions could be made equal to the cost of purchasing sufficient energy outside the Federal system to maintain 100 percent availability to the lower three quartiles of industrial load. Compensation for capacity restrictions could be based on expected capacity interruptions in an average water year. Bonneville estimates the average annual cost of purchasing energy in lieu of second quartile interruptions to be $27.3 million and the annual value of expected capacity restrictions to be $5.0 million. Under this alternative, the average annual availability credit would be $32.3 million.

1/ A reduction in service imposed by BPA on its direct-service industrial customers is referred to as a power restriction. When an industry chooses of its own accord to reduce the amount of power it receives the action is referred to as a power curtailment.

Table VI - 3

INDUSTRIAL FIRM POWER

Each Kilowatt	Curtail by Industry	Restrict by BPA
25%	At any time for any period.	Any time for any period. BPA will give as much notice as possible.
25%[1/]	With some penalty on demand charge.	To the extent that BPA cannot meet its firm commitments, including Industrial Firm Power as a result of-- (1) forced-outage including inability to operate at capacity a Federal generating plant or a generating plant from which BPA secures power. Total restriction in kWh under this category in any calendar year shall not exceed 375 multiplied by the Contract Demand. (2) delays in commercial operation of a Federal generating plant or of a plant from which BPA secures power. (3) transmission outages.
25%	With some penalty on demand charge.	To the extent and for the period that the industry is offered the opportunity to purchase part of the output of a generating plant to provide regional reserves against plant delays and the industry elects to permit curtailment instead of such a purchase.
25%	Pay full demand charge.	Other restrictions by BPA: All the load for up to 5 minutes to maintain stability. One-half the load then operating, but not to exceed in kWh, 50 multiplied by the Contract Demand in any calendar year.

1/ Any curtailment made is first charged at 40% of full demand charge until 3.75% of the total contract demand multiplied by the number of months of contract term (240) is exceeded. Then for the next 3.75% of contract kilowatt months the charge is 90%. After 7.5% is used, purchaser pays full charge.

Alternatively, Bonneville could simply increase the amount of the existing availability credit by the same percentage as its proposed general revenue increase. This would produce a credit of $40 million.

Bonneville's direct-service industrial customers have suggested as an alternative that the credit should be based on the cost of building facilities which would be required to provide regional power reserves if these were not available through special restriction rights on DSI loads. Bonneville's industrial customers have suggested that the value of the industrial reserve, when based on the cost of developing alternative generation, may be at least as high as $200 million annually. Bonneville has not completed its studies to evaluate the value of the industrial reserve; however, an approach (Sarikas, 1979) to quantifying the value of the capacity reserve has been completed and inquiry into the value of the energy reserve is underway.

b. Application of the Design Concept in Bonneville's Existing and Proposed Rates. The industrial availability credit was first introduced in 1974. At that time, the amount of the availability credit was set at a level sufficient to insure that, on the average, the rate increase experienced by direct-service industrial customers would not exceed the 27 percent average rate increase for BPA's other firm power customers. Under BPA's existing rates, the amount of the industrial availability credit would be about $21 million in an "average" water year.

The availability credit which BPA is proposing for the 1979 wholesale rates would total approximately $32 million annually. This figure is based on BPA's estimate of what it would cost to purchase power (assuming it is available) outside the Federal System sufficient to maintain 100 percent availability to the lower three quartiles of the direct-service industrial load and the annual value of capacity restrictions. A more complete discussion of the derivation of the proposed credit is included in Bonneville's Rate Design Study (BPA, 1979a).

Based on BPA's proposed 1980 revenue requirement, BPA would need to derive an average revenue of 6.5 mills per kWh from its firm power sales. The effect of the application of availability credits of varying amounts to the average revenue per kWh derived from 1980 industrial sales is illustrated in Table VI-4 along with the effect on the average revenue required from all other firm power sales needed to cover the industrial credit.

TABLE VI-4

Effect of Availability Credits of Differing Amounts on Industrial Versus Non-Industrial Customers

Amount of Availability Credit	Average Decrease in Industrial Power Costs (Mills/kWh)	Average Increase in Firm Power Costs1/ (mills/kWh)
Existing Credit ($21 million)	.45	.29
Proposed Credit ($32 million)	.70	.44
Credit Increased Proportionate to BPA's Proposed Revenue Increase ($40 million)	.87	.54
Credit Suggested by Industrial Customers ($200 million)	4.31	2.73

1/ Excludes sales to customers with fixed-cost contracts but includes industrial customers.

4. Share-the-Savings Rate.

a. Discussion of the Design Concept. A share-the-savings rate design is based on the concept that rates may be appropriately established between cost of service for the seller and value of service to the purchaser; the latter being the cost of operating the resource which is being displaced. There are many agreements in the U.S. which incorporate a share-the-savings concept for nonfirm energy sales. Two of these are used by the Southwestern and Southeastern Power Administrations which have rates based on a percentage of the fuel savings of the purchaser, i.e., 80 percent or 85 percent of those savings. Other agreements establish the rate halfway between the seller's cost and the purchaser's alternative cost. If utilities in the Southwest did not have surplus energy available from the Northwest, their alternative source would be fossil-fired generation at a cost of between 30 and 40 mills per kWh, based on current estimates.

Alternatives to a share-the-savings rate could include either charging only the additional operating costs required to produce secondary energy (these being only a fraction of a mill per kWh) or charging a price equal to the alternative cost to the purchaser.

b. Application of the Design Concept in Bonneville's Exsting and Proposed Rates. Bonneville's current secondary energy rate was originally developed on the basis of a share-the-savings concept. The contract season service portion of the current firm capacity rate is also based on the share-the-savings principle. When the

Northwest/Southwest Intertie first became operational, oil-fired generation in California had incremental costs of 3 to 4 mills per kWh. Surplus energy costs in the Northwest were 1 to 1.5 mills. Bonneville's rate for surplus energy was 2 mills per kWh between 1965 and 1974, which resulted in an approximate sharing of benefits from displacing output from California's oil-fired generation. However, increases in the value of the resources being displaced in recent years have grossly distorted the relationship which originally existed between BPA's cost of service and the value of secondary energy service to our customers. In 1974 the secondary energy rate was increased to 3.0 mills per kWh during the summer period and 3.5 mills per kWh during the winter period. Presently the operating costs of oil-fired generation have increased to 30-40 mills per kWh, while the average cost of power for BPA has increased to about 7 mills per kWh.

Bonneville is proposing to continue use of a share-the-savings concept in marketing its secondary energy. Secondary energy purchased for the purpose of displacing thermal generation would be priced at one-half the decremental cost[1/] of the purchaser's highest cost resource, with the condition that in no case would Bonneville's rate be greater than 20 mills per kWh or less than 4.5 mills per kWh. The latter rate applies to off-peak hours. During BPA's peak period (7 a.m. - 10 p.m. Monday through Saturday) the minimum rate would be increased to 6.5 mills per kWh. If Bonneville were unable to market surplus power at one-half the cost of the resources being displaced because of market conditions or water conditions, Bonneville would have the option of reducing its rate to an appropriate lower level limited by the minimum rate of 4.5 mills per kWh during off-peak hours or 6.5 mills per kWh during peak hours.

Bonneville is required by law to offer its nonfirm power for sale in the Northwest prior to making any sales to the Southwest. Only when power is unmarketable in the Northwest may it be sold outside the region to the Southwest. In some instances it is expected that Northwest utilities would purchase secondary energy from BPA and would continue to operate those thermal facilities for sale to utilities in the Southwest. Under these circumstances, Bonneville proposes to price its secondary energy to such a utility at one-third of the price at which the Northwest utility sells the output of its thermal facilities to the Southwest. The same floor and ceiling rates apply to such "pass-through" sales as are proposed for direct thermal displacement sales.

All nonfirm sales, other than for thermal displacement, would be made at the floor levels of 4.5 or 6.5 mills per kWh.

1/ That cost not incurred when a plant is shut down.

Because BPA's cost-of-service analysis did not allocate any costs to nonfirm energy, any revenues derived from nonfirm sales under the share-the-savings rate would be excess revenues. The existing secondary energy rate distributes the excess revenues from secondary sales to firm power customers in the form of somewhat reduced rates for firm power. Under BPA's proposal, revenues derived from nonfirm energy sales would first be applied to off-peak capacity costs, thus eliminating the charge for off-peak capacity. Any additional revenue from secondary energy sales would be assigned to offset a portion of the cost of secondary peak period capacity. As discussed in Section C.1. of this Chapter, these revenue assignments were intended to reflect the results of BPA's long-run incremental cost study.

It is expected that sales of nonfirm energy would be at an average rate of about 8 mills per kilowatthour under BPA's proposal. This would represent an increase over the existing average nonfirm rates of 3.0 and 3.5 mills per kilowatthour. This increase should affect the amount of nonfirm energy purchased from BPA since the secondary rate guarantees purchasers substantial savings relative to their alternative generation costs. The increased rate for nonfirm energy would increase the overall cost of power to retail customers of utilities purchasing nonfirm energy from BPA thereby resulting in less consumption by those consumers than would otherwise occur under existing rates. However, as was noted above, BPA's nonfirm energy would be substantially less expensive than the purchasers alternative resources. It would be difficult to estimate the impact of the increased nonfirm rate on consumption since it is unknown what proportion of the increased nonfirm energy cost would be incurred by Northwest customers and what proportion might be passed through to Southwest utilities purchasing from Northwest utilities. Furthermore, the availability of nonfirm energy is dependent on water conditions which vary from year to year. However, the overall effect on the amount of nonfirm energy purchased from BPA would be insignificant.

The significance of the proposed increase for retail power rates would be small in most cases; however, the extent of the effect would vary depending on what portion of a utility's total energy requirements were purchased under the proposed share-the-savings rate. The City of Glendale, California, for example, has estimated that impacts on their costs could be considerably more significant than for BPA's larger California customers. They estimate that, had their nonfirm energy purchases in 1974 and 1975 been at an average rate of 15 mills, their overall cost for energy would have been increased 8 percent and 24 percent, respectively (see Appendix D, page 58). As previously stated, BPA is estimating an average rate of about 8 mills for secondary energy.

Bonneville's existing capacity rate schedule (F-6) is for the sale of firm peaking capacity without energy. This schedule separately identifies rates for annual capacity (delivery of capacity throughout the area as requested by the customer) and seasonal capacity (capacity delivered for a contract season of 5 months from June 1 to October 31, principally to Southwest utilities). The basic charge for firm capacity for contract year service is $12 per kilowatt per year of contract demand. For contract season service, the basic is $6.50 per kilowatt per season per contract demand.

The contract season and variable charge portions of Bonneville's proposed firm capacity rate (F-7) is based on share-the-savings principles. The contract year rate for annual capacity is based on adjusted data from FCRPS Cost of Service Analysis.

For contract season service, staff pro-rated an estimated annual combustion turbine cost of $32.40 per kilowattyear over a 5 month contract season deriving an estimated resource cost of $13.50 per kilowatt season. Bonneville's resource and transmission cost (excluding intertie costs) equals $5.95 per kilowatt ($1.19 per kilowattmonth for 5 months). Application of the share-the-savings principle yields a net rate of $9.73 (one-half the sum of $13.50 and $5.95) per kilowatt season.

To encourage capacity purchasers to limit their usage of Federal generating facilities, both the seasonal and contract year capacity rates have an additional monthly charge of $0.265 per kilowattmonth for each additional hour of capacity in excess of 6 hours per day during peak hours (7 a.m. through 10 p.m. excluding Sundays). Development of the charge for sustained peaking is based on share-the-savings principles applied to an estimate of the fuel savings realized by the customer by not having to operate a peaking plant. The reason for this additional charge is that the Federal hydropeaking system cannot generate as much capacity during sustained daily periods (e.g., in excess of 6 consecutive hours) as it can for shorter periods (e.g., less than 6 hours).

Since the proposed contract season service and the variable charge rates are based on the share-the-savings principle, excess revenues will be produced. Staff analysis indicated that sales of firm capacity would average 10 hours per day. Four hours of demand duration in addition to the allowable 6 hours will produce an excess revenue of $14.6 million. Excess revenues from contract season service is estimated at $2.3 million.

5. Facilities Charge.

a. Discussion of the Design Concept. Bonneville is the designated marketing agent for the output of the Federal hydroelectric facilities in the Pacific Northwest, and it has also assumed the responsibility of providing a major portion of the main grid transmission facilities for the regional power system. Most of BPA's operations involve bulk power sales, and its facilities must be designed and constructed accordingly.

When transmission lines are appropriately loaded, the unit costs ($/kW) for higher voltage lines are generally lower than for lower voltage lines. Therefore, it is generally more economical to transmit and deliver power at high voltage than at lower voltages. Also, transmission losses are proportionally less for a given quantity of power transmitted at high voltages than at lower voltages. Consequently, BPA constructs its facilities at the highest voltage practical for transmitting and delivering power required by the existing and projected loads to be served.

In most areas, BPA facilities are constructed and operated at a higher voltage than is practical for the distribution system operated by the utility serving the area's ultimate consumers. Transformers must be installed, either by BPA or by its utility customer, to change the voltage of the power from BPA's transmission voltage to the subtransmission or distribution voltage used by the utility.

In designing rates, Bonneville may choose one of several methods for recovering the cost of facilities required to transform power from transmission to distribution voltages. From a cost-of-service standpoint it might seem appropriate for BPA to base transformation charges on the actual cost of transformation provided to individual customers. However, such a charge might well be beyond the ability of many of Bonneville's smaller rural customers to pay, and would therefore interfere with BPA's commitment to encourage the widest possible use of electrical power. Also, facilities required for low voltage deliveries represent only a relatively minor (less than 9 percent) portion of BPA's total transmission investment, the balance of which is financed through the application of a uniform capacity charge despite wide variation (due to such factors as, for example, distance from generation facilities) in the cost of transmitting power to individual customers.

Bonneville could have a uniform rate for all transmission service. Such a rate would be designed to recover all costs associated with delivering power to customers, but would not reflect differences in delivery costs among customers. Alternatively, BPA might choose to charge actual service costs for only those services where cost assignment clearly can be made and not in those circumstances where joint use may make cost allocation controversial.

Prior to 1974, as an integral feature of its postage-stamp pricing, BPA often provided the necessary delivery point transformation and included the recovery of the cost of these facilities in the uniform rates paid by all its customers, regardless of the difference in costs of providing these facilities for specific customers. The facilities charge which BPA initiated in 1974 was intended to reflect the costs of transformation and related facilities required to deliver power to BPA's customers at lower voltage than the existing transmission voltage. Any customer receiving such service would pay a charge for the facilities which BPA furnished.

The existing rate schedule for firm power includes a two-level charge for deliveries of power at voltages less than the highest voltage available at a substation delivery point at which BPA provides transformation. If the utility provides its own transformation in a BPA substation, or BPA provides transformation in a utility substation, the charge is half as great as whichever of the two levels would otherwise apply.

Because the low voltage transformation charge is added to the fixed demand charges applied to the monthly billing demand, the resulting increase in average cost of energy decreases as the monthly load factor at which the power is taken increases. For an average utility purchasing approximately one-third of its power requirements in the summer and taking delivery of all its requirements on BPA at voltages requiring transformation to a voltage between 100,000 and 150,000 volts from a higher or lower voltage, the existing facilities charge increases total power costs by approximately 6.5 to 7 percent. If the same utility were taking delivery at voltages requiring BPA transformation to less than 100,000 volts, the increase in total power costs would be approximately 11 to 11.5 percent, unless the utility were to provide part of the facilities itself, in which case the increase would be only 5.5 to 6 percent.

Under BPA's proposed firm power rate the facilities charge would be "rolled in" to the basic firm power rate. This would have the effect of distributing the cost of final delivery facilities across all of Bonneville's firm power customers regardless of their point of delivery voltages. The existing facility charge distributes all the cost of low voltage delivery facilities only to those customers (generally Bonneville's smaller customers) requiring them. However, since the existing charge does not apply to high voltage facilities, the costs of which are "rolled in" to the basic firm power rate, the existing charge forces customers receiving power at low voltages to subsidize delivery costs to high voltage customers in addition to paying for low voltage facility costs.

6. At-Site Discount.

a. Discussion of the Design Concept. Bonneville's transmission system costs represent a major portion of the cost of providing electrical service to BPA's customers. As mentioned in the preceding section, the actual costs of transmitting power to specific customers varies widely. An at-site discount could be employed by Bonneville based on the fact that customers which take power within a short distance of generation facilities are less costly to serve because of their relatively limited transmission requirements. These customers do derive some benefit from Bonneville's transmission system as a whole, however, due to the greater reliability provided. For this reason it is appropriate for such customers to share, to a limited extent, in the costs associated with the entire transmission system.

b. Application of the Design Concept in Bonneville's Existing and Proposed Rates. Bonneville currently offers an at-site discount on the capacity charge of its firm power rates. The discount applies to power purchased for use within 15 miles of a powerplant. At-site power is exempt from the transformation charges currently applicable to other firm power and the capacity charge is discounted $0.10 per KW per month below the standard firm power capacity charge of $1.05 during the winter period and $0.93 during the summer.

The adjustment is derived from the rate which was in effect at the time contracts were negotiated for at-site power. The reason for this adjustment is that at-site customers are entitled by contract to the adjustment. At-site customers do benefit from the transmission system from a reliability standpoint and therefore should pay some, if not all, the cost associated with the transmission system.

The at-site discount would be continued in modified form under BPA's proposed firm power rate. Based on results of the FCRPS Cost-of-Service Analysis for fiscal year 1980, an adjustment equal to the total unit transmission cost would be about $1.07 per kilowatt per month. However, in the proposal the discount would be increased to $0.257 per KW per month under Bonneville's proposal. Since elimination of the existing transformation charge is proposed, the additional benefit of exemption of at-site customers from transformation charges would cease to exist.

The proposed at-site adjustment conforms to contract provisions while recognizing that some transmission costs should be recovered from at-site customers.

An alternative to the existing and proposed at-site discounts would be discontinuance of the at-site discount. This would be inconsistent with BPA's cost-of-service analysis, with the goal of maintaining rate continuity, and with current contracts.

Only two of Bonneville's existing customers qualify for the at-site discount and it is unlikely that continuance of the discount would produce any significant environmental impacts. Elimination of the proposed discount would result in a capacity charge approximately 18 percent higher than under the proposed discount for those customers eligible for the proposed discount and would have a negligible effect on rates paid by other power customers. This magnitude of increase in power cost to these customers should create no significant environmental impact.

7. Baseline Power Rate. The recent introduction of significant costs associated with thermal power facilities into BPA's revenue requirement has stimulated interest in the concept of segregating the cost of thermal power from the cost of Bonneville's other (hydro) generation resources. These cost differences might be used as a basis for establishing separate rates for thermally versus hydroelectrically generated power. The less expensive hydroelectric power could be marketed at a "baseline" rate. This rate concept in some ways resembles the lifeline rate concept which has recently received considerable attention as a means of mitigating the effects of rapidly rising energy costs on certain classes of consumers. The baseline rate could be used to preserve the benefits of BPA's historically low cost hydro resources for a limited segment of regional power consumers.

Bonneville has undertaken preliminary study into the possible basis for and feasibility of implementing some type of two-tier baseline rate. It is the opinion of Bonneville's General Counsel (Ratcliffe, 1979) that Bonneville currently lacks authority to implement rates based on cost differences between thermal and hydroelectric generation plants. The net-billing agreements which were established with the approval of Congress authorized BPA to market power for thermal power plants owned and constructed by non-Federal interests and to "meld" or average the cost of this thermal power into its power rates. Therefore, Congressional concurrence may be required prior to any abandonment of the melded rate concept.

Two basic methods for developing potential baseline rates have received preliminary study by Bonneville. Under one method, a baseline rate would be based on the cost of providing from Bonneville's lowest cost generation resources whatever amount of power would be marketed at the baseline rate. The second-tier rate, or that rate applied to power not marketed at the baseline rate, would be based on the cost of all of BPA's resources not assigned to baseline service.

An alternative to the lowest cost resource baseline scenario just described would be to market a limited amount of power at a rate based on the average cost of generation from BPA's hydroelectric facilities with all remaining power being based on a weighted average of the cost of BPA's net-billed thermal generation and of that portion of Bonneville's hydroelectric generation not required for load served under the baseline rate.

Under a lowest cost baseline rate the level of both the baseline and second-tier rates would depend on the magnitude of load accorded baseline treatment. Under a two-tier hydro/thermal rate the baseline rate would simply reflect average hydro cost. This cost would vary slightly in the future due to increases in operation and maintenance expense and the addition of new units. The second-tier rate, however, would be affected by the amount of load given baseline status since this would determine the amount of hydrogeneration to be averaged with thermal generation in establishing a second-tier hydro/thermal rate.

Factors influencing the amount of load served at a baseline rate would include the composition of the class of customers eligible for the baseline rate and the amount(s) of power which eligible customers could purchase under the baseline rate. For example, BPA might choose to limit baseline treatment to residential loads or perhaps to irrigation loads or to both. In addition, such treatment might be further constrained by serving only a limited amount (say 900 kWh per month) of load per retail customer at the baseline rate.

In Table VI-5 are presented estimates of the cost associated with generation in 1980, assuming cost assignment based on a lowest cost resource versus an average hydro method, for various baseline eligibility scenarios. As these data indicate, increases in the amount of load accorded baseline treatment would result in increases in both the baseline and second-tier rates under the lowest cost resource case. Only the second-tier cost would increase for the hydro/thermal case, assuming the baseline load did not exceed BPA's hydro capability. This is due to the fact that under the lowest cost method increases in the baseline pool would require the addition of ever more costly resources to the rate basis of the baseline tier while, under the hydro/thermal scheme, baseline cost would be affected only if the amount of power in the baseline pool exceeded that amount available from BPA's hydro resources. Nevertheless, due to the relatively small proportion of power coming from thermal generation in 1980, the difference between baseline and second-tier rates is relatively small when compared with retail power costs.

As additional thermal power is integrated into BPA's system, the significance of a baseline rate would increase. Table VI-6 contains estimates of the rate consequences which might be expected to result from the application of each of the baseline scenarios under discussion by the year 2000. The impact of either type of baseline rate on second-tier customers would be substantial with second-tier costs running around 7 or 8 times those for baseline resources under the lowest cost resource case and 2 to 4 times the baseline cost in the hydro/thermal case. A more detailed discussion of these matters is presented in BPA's (1979) Issue Paper on Baseline Rates.

A technical problem to be overcome in implementing a baseline rate would be that of insuring that the economic benefits of a wholesale baseline rate are faithfully reflected in retail rates. In other words, if utilities receive a baseline rate for that portion of their load devoted to serving residential customers, the wholesale power savings to the utilities should result in retail costs to residential customers being lowered by an amount equal to the

TABLE VI-5

BASELINE AND SECOND TIER COSTS IN THE YEAR 1980

Baseline Category	Total Baseline Consumption (GWH's) 1/	Lowest Cost Resource Assumption		Average Cost Hydro Assumption	
		Baseline Rate	Second Tier Rate	Baseline Rate	Second Tier Rate
Public Agency Customers:					
Total Irrigation Load	4,000	1.22	5.24	4.79	5.06
Residential Minimum	10,000	1.28	5.56	4.79	5.08
Residential Minimum with Space Heating Allowance	16,000	1.45	5.91	4.79	5.11
Total Residential Load	24,000	1.56	6.46	4.79	5.15
Total Residential and Irrigation	28,000	1.60	6.80	4.79	5.18
Public Agency and Investor-Owned Utilities:					
Total Irrigation Load	4,000	1.22	5.24	4.79	5.06
Residential Minimum 2/	23,000	1.55	6.39	4.79	5.15
Residential Minimum with Space Heating Allowance	42,000	1.69	8.49	4.79	5.31
Total Residential Load	54,000	2.04	10.65	4.79	5.53
Total Residential and Irrigation	58,000	2.14	11.79	4.79	5.65

1/ Includes distribution losses of 6 percent.

2/ Investor-owned utility irrigation loads are included in the residential figure.

TABLE VI-6

BASELINE AND SECOND TIER COSTS IN THE YEAR 2000

Baseline Category	Total Baseline Consumption (GWH's) 1/	Lowest Cost Resource Assumption: Baseline Rate	Lowest Cost Resource Assumption: Second Tier Rate	Average Cost Hydro Assumption: Baseline Rate	Average Cost Hydro Assumption: Second Tier Rate
Public Agency Customers:					
Total Irrigation Load	11,000	2.18	17.60	8.29	16.86
Residential Minimum	21,000	2.42	19.44	8.29	17.92
Residential Minimum with Space Heating Allowance	38,000	2.95	23.64	8.29	20.48
Total Residential Load	58,000	4.12	31.49	8.29	26.00
Total Residential and Irrigation	69,000	5.60	37.51	8.29	31.89
Public Agency and Investor-Owned Utilities:					
Total Irrigation Load	11,000	2.18	17.60	8.29	16.86
Residential Minimum 2/	49,000	3.32	27.58	8.29	23.00
Residential Minimum with Space Heating Allowance	87,000	11.20	43.27	8.29	60.04
Total Residential Load	121,000	3/	3/	3/	3/
Total Residential and Irrigation	132,000	3/	3/	3/	3/

1/ Includes distribution losses of 6 percent.
2/ Investor-owned utility irrigation loads are included in the residential figure.
3/ Exceeds expected Federal generation capability in the year 2000.

wholesale rate benefit to the utility. This problem could be further complicated if, for example, it were BPA's intent to serve say the first 500 kWh per month consumed by each of a utility's residential customers. In addition to in some way insuring an appropriate pass through of savings, BPA would have to have a reliable means of determining the number of residential customers being served by the utility in order to bill an appropriate amount of power at the baseline rate.

The impact of a baseline rate would vary considerably depending on the amount of resource committed to baseline service and the group to which baseline rates were applied. Baseline rates might be an effective means for insulating financially vulnerable groups (such as low income residential consumers and, possibly, irrigators) from the burden of anticipated future increases in power costs, especially if the total loads of residential customers were granted baseline status. Users not eligible for baseline treatment would be adversely affected, however, and might question the equity of exclusive baseline rates.

The effect of baseline rates on consumption could vary depending on the resulting rate levels and the relative price sensitivities of customers purchasing power with and without baseline benefits. Baseline treatment of customers with price sensitivities above the average would cause an increase in overall power consumption. If baseline rates were applied to only those customers with very inelastic demands (demands not sensitive to price) and customers with relatively elastic demands were required to pay second-tier rates, overall consumption would decline since the baseline rate would require a second-tier rate higher than an average cost based rate, thereby discouraging consumption among the price sensitive second-tier customers. Since the difference between baseline and second-tier rates would currently represent only a minor portion of retail power costs, employment of a baseline rate would not be expected to significantly impact regional power consumption in the short run. As the differential between baseline and second-tier rates becomes greater, however, the significance for regional consumption may increase.

b. Application of the Design Concept in Bonneville's Existing and Proposed Rates. Bonneville has traditionally pursued a policy of uniform rates for all of its firm power. Both Bonneville's existing and proposed rates are uniform for all firm power sales. The continued employment of uniform rates would conform to BPA's rate design objectives of achieving equity and stability of rates while maintaining them at the lowest possible level consistent with sound business principles.

8. Special Irrigation Rate.

a. Discussion of the Design Concept. Several arguments have been made by BPA customers and farmers as to why Bonneville should implement a special rate to apply to power consumed by irrigators. First, BPA's existing rates contain a 0.9 mill per kWh seasonal differential in the energy charge. The proposed rates also have a seasonally differentiated energy charge; however, the differential (0.4 mill per kWh) is smaller than the existing energy differential. Therefore, the benefit derived by irrigators (who consume most of their power during the off-peak summer period) under BPA's proposed seasonal differential would be smaller than under the existing rate structure. This may cause them to face economic impacts more serious than those experienced by other customer groups.

Second, power costs represent for irrigators a significantly greater portion of their production costs (as much as 20 percent in some cases) than is the case for most other power customers. Furthermore, farming is a highly competitive enterprise involving a large number of independent entrepreneurs. As a result it is difficult for farmers to recover increases in production costs by passing these costs on to consumers through higher prices.

Third, prior to 1974, BPA offered a special irrigation discount to utilities in an effort to develop a market for what was at that time unsaleable secondary energy. With the development of large storage reservoirs, however, the rationale for the irrigation discount ceased to exist and Bonneville chose to discontinue it. Nevertheless, some irrigators have expressed the belief that they were misled into making large investments in land and equipment based on BPA's previous pricing policies and that BPA is now violating their trust.

An alternative to the baseline rates discussed in the preceding section would be to offer utilities serving irrigators a discount which would be sufficient to limit the average percentage increase in the BPA wholesale cost of power to supply irrigators to the average percentage increase in wholesale power costs experienced by all other BPA customers. According to BPA's analyses this would require a discount of 0.2 mill to be applied to all power used for irrigation. A discount of this magnitude would create a revenue deficit of about $570,000 for Bonneville -- an amount equal to about than one-tenth of one percent of Bonneville's anticipated 1980 revenue under the proposed rates.

b. Application of the Design Concept in Bonneville's Existing and Proposed Rates. Neither Bonneville's existing nor its proposed rates provide for a special rate for power used by irrigators. However, as previously indicated, both the existing and proposed firm power rates contain seasonal energy and capacity differentials which reflect the lower costs to BPA for serving summer power needs. The lower summer rates are beneficial to irrigators because they result in lower costs to this group of consumers.

9. Rate Incentives for Conservation.

a. Discussion of the Design Concept. The concept of a conservation rate can encompass a significant number of alternatives. Some of the alternatives would apply more appropriately to utilities which sell power to ultimate consumers while others could apply to Bonneville which is primarily a wholesaler of power.

The application of either a two-tier hydro/thermal rate or some other type of baseline rate would, as indicated in section 7 of this chapter, have very little effect on overall consumption.

In some cases, time differentiated pricing has been suggested as a possible conservation measure. For example, Pacific Gas and Electric Co. filed a time-of-day rate schedule in response to the California Public Utility Commission's directive to "make conservation in the sense of efficient allocation of electricity the keystone of the rate structure" (PG&E, 1977, p. 2). Several environmental groups have also urged the adoption of peak-load pricing for conservation and environmental purposes (e.g., NRDC, 1974, p. 47; Habicht, 1975, p. 87; Blomquist, 1976, p. 8; Sierra Club, 1977, p. 9), although two other environmental groups in Wisconsin have opposed the implementation of time-of-day rates for industries because they view the off-peak rates as "promotional--not conserving" (Electrical Week, Jan. 23, 1978, p. 4).

Actual experience with time-of-use rates has provided mixed results with regard to conservation. Tests in California and Connecticut revealed that users decreased their kilowatthour use by a small amount in response to time-differentiated rates (CERCDC, 1977, pp. 58, 84), but Vermont users increased their total consumption by about 10 percent (Romano and Elliott, 1977, p. 26).

These experiments have shown that systems with a large saturation of electric water and space heat are likely to experience an increase in total kilowatthour consumption with time-of-day rates. Because the customers of BPA's preference utilities have, as a group, more electric water and space heating appliances than do customers of other utilities, time-of-day rates could increase total kwh consumption in the Pacific Northwest.

Flat or inverted rates have also been promoted as conservation tools. It is claimed that by providing for a flat rate for energy, either within the residential class or among all classes, or by inverting the rate structure so that larger users will pay more per unit as consumption increases, utilities create an incentive to keep consumption low. In contrast, declining block rates, which are prevalent among Northwest utilities, are said to provide a reward for increasing consumption by reducing the average rate paid for electricity.

No known empirical studies have been conducted on the effect of flat or inverted rates on conservation, but two theoretical studies have suggested that there may be no conservation effects. Wilson and Uhler, in a study of inverted rates, stated that the incentive for industries to construct two smaller, more inefficient facilities in place of one large plant (to take advantage of lower rates for small users) could result in more electricity consumption (1974, p. 86). However, it is probable that the conservation efforts of larger industries which are unable or unwilling to build smaller plants could more than offset the effect that Wilson and Uhler discussed. A conclusion reached in an econometric study done for the Federal Power Commission (FPC, 1975, p. 38) was that "there is no evidence to support the contention that flattening rate schedules will lead to drastic reductions in the use of electricity. In fact, there might be a slight expansion of consumption, which could be attributed to an increased use by customers who currently use small quantities of electricity that is sufficient to offset reductions made by larger users."

Solar systems which use electricity as a back-up energy source place unusual demands on an electric utility. The solar customer has a much lower annual load factor than a conventional electric heat customer, greatly affecting the utility's coincident seasonal peak but probably serving to mitigate the normal daily peak (see Mitre Corp., 1977, p. 2; Dickson, et. al., 1977, p. 196; Koger, 1978, p. 11). Different rate structures can serve as either an assistance or a detriment to solar system economics because of that load pattern.

A rate structure that contains a demand charge in addition to an energy charge will tend to discourage investment in solar devices (Mills, 1977, p. 42; Mitre Corp., 1977, p. 3). The demand charge, when applied to the relatively few days when the user must rely on the electrical backup system, will penalize the solar customer with a low load factor. Currently, utilities in the Pacific Northwest apply a demand charge only to commercial and industrial customers.

Average cost rates which charge only for energy are more beneficial to solar energy users. Dickson, et. al. (1977, p. 202), claim that solar-heated buildings are "subsidized by other consumers" under such rates because of the much higher peak-to-energy ratio of solar systems.

All observers agree that time-of-day rates are most attractive to solar customers (Mitre Corp., 1977, p. 7; Koger, 1978, p. 11; Habicht, 1975, p. 90; Uhler, 1977, p. 63; Mills, 1977, p. 44). Generally, the solar system would be able to rely on stored heat or direct sunlight during the utility's peak hours. During longer periods of overcast skies it could charge thermal reservoirs at night, thus making use of lower cost off-peak electricity. A few utilities have proposed experimental rates for the promotion of solar energy development (e.g., Los Angeles Department of Water and Power, Pacific Gas and Electric Co., and Detroit Edison Co.), and each proposed rate contains a time-of-day feature.

A seasonal rate for a winter peaking utility would raise the utility bill for solar customers, since it is primarily during the winter that such consumers rely on the electrical backup system. These impacts would be further increased if the rates included a demand charge.

Bonneville's aluminum customers may represent a special class where BPA might be able to apply a special rate designed to encourage conservation. The reason for this is that the aluminum companies, because they all produce the same product, provide a basis for efficiency comparisons between them. The amount of power consumed by these industries per pound of aluminum currently ranges from approximately six to nine kilowatthours. Conceivably BPA could offer power to these companies based on a sliding rate scale which would provide for progressively decreased rates as production efficiency increases. On the other hand, however, these industries are expected to be relatively insensitive to price changes unless the price exceeds something in the range of 20 to 25 mills. In order to be effective, therefore, it might be necessary to employ extreme price differentials to these customers.

b. Application of the Design Concept in Bonneville's Existing and Proposed Rates. Bonneville employs a flat rate structure in its existing rates and intends to follow the same principle in its proposed rates. Both the existing and the proposed rates include seasonal differentials which may discourage consumption of energy during the winter peak period if they are passed on to the ultimate consumer. The proposed rates for firm power, industrial firm power, and firm capacity all contain daily time-differentials which provide customers with incentives for minimizing requirements during peak periods. The minimum rate for nonfirm energy sales also contains a daily time-differential.

As previously discussed in Section C.1. of this Chapter, Bonneville's proposed rates assign proportionately more of BPA's revenue burden to energy (as opposed to capacity) than do the existing rates. This is expected to encourage customers to increase their efforts to conserve energy.

The most significant conservation effect of the proposed rates is expected to result from their level rather than their structure.

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CHAPTER VII

MITIGATING MEASURES

This section addresses a variety of ways in which the impact of BPA's proposed rate increase would or could be mitigated. These include both proposed and existing government income support programs designed to assist low-income or elderly persons, programs which could be developed by BPA to assist consumers in increasing energy efficiency, and identification of rate modifications which could reduce the severity of impact experienced by all or by limited portions of Bonneville's customers.

A. Modification of Rates

A graduated increase in rates could ease the initial impact of higher rates. The primary value might be more pyschological than financial, however, at least in the long run. Such a technique may not be justifiable from a cost-of-service standpoint, since ratepayers would be paying less than cost-of-service at first and would eventually need to pay more than cost-of-service to make up for the deficit created earlier. Bonneville's adoption of an annual rate review period beginning in 1980 has served to minimize the size of the rate increase required in 1979. If BPA were unable to again increase rates for 5 years after the proposed 1979 increase, the 1979 increase would have to include additional amounts to cover the possibility of inflationary increases over the entire 1979-1984 period as well as costs for additional higher cost thermal resources which would be required to meet loads during the latter part of the 5-year period.

Special rate adjustments could be made to provide rate relief to those customers expected to be most seriously impacted by the proposed increase. The possibility of offering baseline rates to certain groups of customers was discussed in Chapter IV. In addition to those cost based baseline rates BPA might simply freeze rates for power sold to certain customer classes and make up the resulting deficits through higher rates to other customers.

B. Energy Efficiency Programs

One effective way of reducing the impact of increased rates on customers is to assist them in reducing their consumption levels. There are many ways in which this could be accomplished. A basic approach to reducing consumption could revolve around consumer education. Recent research (Opinion Research Corporation, April 1975, p. 35) indicates that consumers' beliefs about the existence of an energy crisis are directly related to their efforts to conserve energy. Insuring that electricity customers are accurately informed regarding energy requirements, supplies, and costs should assist in minimizing consumption. BPA, through its public information and conservation offices, is attempting to make information on energy available to the public, its customers, and its employees.

A variety of methods not presently employed by BPA could be used to better educate the public regarding energy consumption. For example, Bonneville could assist in the development of a regional energy extension service, expanding on the trial program currently being established in the State of Washington. The function of such a service would be to provide educational programs and direct information assistance programs for persons or groups interested in implementing conservation measures. Bonneville could also lend financial support to other State, local, and utility public information programs. Opportunities for supporting stricter standards for energy efficiency in building and appliance construction could be vigorously pursued. (See BPA Role EIS, Appendix C, pages III-129 to III-138 for a more complete discussion of BPA's conservation alternatives.) Bonneville is currently in the process of developing a conservation policy.

The largest single use of electricity in the Northwest is space heating. Improving the thermal efficiency of electrically heated homes could, therefore, be a very significant means of reducing electricity bills. BPA has proposed a program which could assist in improving home insulation levels (BPA Role EIS, Appendix C, pp. II-82 to II-86). This program would assist consumers desiring to install additional insulation in their homes by providing low-interest loans and possibly partial subsidies. Although not currently anticipated, the amount of subsidy could conceivably be related to consumers' income levels.

A limited number of consumers may mitigate the effects of increased electricity rates by replacing existing appliances with more efficient models or switching to less expensive fuels such as natural gas. On the average, about 65 percent of household electricity is consumed by appliances and lighting, and a surprising amount of potential exists for appliance efficiency improvements (Booz-Allen and Hamilton, 1976, p. II-2). By and large, however, these options would be unavailable to the poor since they are unable to make the required capital expenditures.

C. Present Income Support Programs

Several current major government income assistance programs would provide limited mitigation of the effects of an electricity rate increase on lower income families. The Federal Food Stamp Program provides low income persons with coupons which can be used to purchase groceries. The cost of the coupons depends on the applicant's income after deductions are made for the cost of certain necessary commodities and services, including the amount used to purchase electricity. Any increase in electricity expenditures would result in a decrease in the applicant's income after deductions under the Food Stamp Program, thereby decreasing the amount of money charged for his coupon allotment. In most cases, however, the reduction in coupon cost would offset no more than 25 to 30 percent of the increase in expenditures for electricity.

Another Federal program which can provide assistance to low income families is the Aid to Families with Dependent Children (AFDC) program. Although a number of States consider the utility bills of individuals in allotting funds, the States in BPA's service area have developed standards for basic maintenance costs which are applied to all families. Families with expenses exceeding these standards would receive no additional assistance. Therefore, as applied in Bonneville's service area, the AFDC program would not directly mitigate an increase in electricity bills. Presumably, however, the States involved might make adjustments in their standards for significant increases in the cost of electricity. Any such adjustment would probably be made only after considerable lag time, however, and would cover only a portion of the increase in costs. Furthermore, since the standards are applied to families without regard to individual utility expenditures, the proportion of the increase in electricity bills covered for large users (i.e., those with electric space and water heating) would be less than for small users.

The Federal Supplemental Security Income Program is designed to assist blind, aged, or disabled low-income individuals. Although benefit levels are not tied directly to electricity costs, increases in benefits are dependent on increases in the Consumer Price Index. Since such increases would be dependent on nationwide changes in prices, they would be relatively insensitive to increases in regional electricity costs.

D. Other Possible Income Support Programs

One proposal which has received widespread attention as a means of easing the burden of increasing energy costs on the poor focuses on the issuance of energy or fuel stamps. Several resolutions (e.g., H.R. 16140, July, 1974; H.R. 17316, October, 1974) proposing energy stamp programs have been introduced in Congress, but none have yet become law. Experimental fuel stamp programs have been conducted in the Cities of Denver, Colorado, and Lehigh Valley, Pennsylvania (Berg and Roth, 1976, p. 691). Also, an energy cost assistance program is currently being developed by the State of Kentucky. Although still in the planning stage, the program is expected to distribute $5 million per year for 2 years to qualified individuals. Grants ranging between $50 and $80 would be made either directly to individuals or to energy suppliers. The size of the payment would depend on the applicant's income and would be limited to persons who are aged, blind, or totally and permanently disabled (Reynolds, 1978).

In order to avoid administrative duplication, the incorporation of an energy stamp feature into the current food stamp program would appear to be most efficient. Persons qualifying for food stamps would also be able to obtain energy stamps with the cost of the stamps being dependent on the applicant's income after deduction of allowable expenses. The fuel stamps could then be used in paying utility bills. Since climate, utility rates, size of home, etc. would vary from customer to customer, it would be difficult to establish a standard allocation procedure. On the other hand, consideration of a variety of characteristics for each applicant could pose overwhelming administrative problems. The administration of this type of program would be through the State and local public assistance system. (For a comparison between fuel stamp and lifeline rate programs, see Joskow, 1975.)

Another method of mitigating the financial effects of higher electricity prices could involve a tax allowance for such costs; however, unless the allowance were reflected in reduced withholding payments, the consumer would have to wait for a tax refund before experiencing any relief. Utilities could not be expected to defer payment of bills until after a customer's receipt of a tax refund. Also, those persons who pay no tax would receive no benefit unless actual cash payments were made to them in perhaps the form of a negative income tax.

To overcome the problem in the region associated with higher electricity bills during the winter months (especially for customers with electric heat), many utilities offer programs providing for equal monthly utility payments. Another approach to mitigating peak costs for low-income customers could involve the use of an emergency short term loan program, perhaps sponsored by State and local welfare service agencies and administered through utilities. Unusually high electricity bills could be paid over a period of several months rather than all at once.

Governmental subsidies could be used to offset higher energy costs for low-income persons. Utilities could receive a special low-cost block of power for distribution to needy customers or governments could simply reimburse the utilities for the losses created by low-cost service to low-income consumers. The administrative aspects of such a program could be quite complex, however.

Lifeline or inverted block rates are also being proposed and, in a number of cases, implemented as methods for reducing the impacts of increases in electricity rates (Electrical Week, August 22, 1977; March 13, 1978; April 10, 1978; and June 5, 1978; NARUC Bulletin, April 17, 1978; February 2, 1976; February 20, 1978; Public Power Weekly, January 17, 1977; Public Utilities Fortnightly, October 13, 1977). One of the problems with these strategies is that their benefits are tied only to level of use. There is no guarantee that they would mitigate the effects of a rate increase for those customers on limited or fixed incomes who consume relatively large amounts of energy and would therefore be affected most significantly. If the revenues lost on low-consumption customers were recovered through higher charges to consumers using more than minimal amounts of electricity, the impacts on a substantial portion of low-income customers could be severely aggravated (Berg and Roth, 1976; Joskow, 1975; Howe, 1976; Pace, 1975; Reed, 1973). A study by the Tennessee Valley Authority (Radin, 1977, p. 10) indicated that implementation of a particular lifeline rate within its system would have resulted in increased bills for 26 percent of its low-income customers and decreased bills for 49 percent of its high-income customers. Of course, the 26 percent paying more were precisely those already faced with the largest electricity bills.

E. Other Mitigation

By providing forewarning of rate increases, BPA could further reduce adverse rate impacts. Consumers could take projected rate increases into account when purchasing homes or appliances or when considering the future advantages of home insulation, storm windows, and so forth. Consumption could be reduced prior to the implementation of higher electric rates. Bonneville has attempted to provide maximum forewarning of impending rate increases through the use of news releases and the inclusion of relevant material in speeches given by the Administrator and other agency officials. Additionally, BPA, through its environmental impact analysis and public involvement procedures, intends to provide both the general public and its wholesale customers with detailed information on rate increases prior to their implementaiton.

F. Mitigating Measures for Air Quality Impact

Bonneville's rate policies may affect air quality through two mechanisms: they may affect the demand for electricity, which would vary the degree of air quality impact from the generation of electricity and from the end use of that electricity, and they may cause substitution of other fuels for electricity. Higher rates would mitigate the first mechanism while promoting the second.

Impacts of both mechanisms could be mitigated by promoting conservation measures and alternate on-site energy systems, such as solar heating and wind generators, by such means as public education, incentive programs, alteration of building codes, and imposition, if necessary, of mandatory standards (see Section C, page 125).

There are a number of existing means to mitigate adverse air quality effects produced by BPA rate policies. Local, State and Federal air quality control agencies survey air quality and enforce emission regulations, vehicle inspection programs, requirements for air contaminate discharge permits for major sources, prevention of significant deterioration regulations, restrictions on certain types of activity such as open burning, etc., in an effort to reduce and then maintain concentrations of air pollutants below allowable limits. Presumably, these agencies would take steps to prevent, limit, or counteract potential adverse air quality effects of BPA rate policies. Some steps they could take would be imposition of stricter air pollution control regulations in general or for fuel combustion sources in particular; mandating periodic inspections of furnaces in homes and commercial buildings to insure that they are operating so as not to produce excessive emissions; and limiting sulfur contents of fuel which could be burned.

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CHAPTER VIII

UNAVOIDABLE ADVERSE IMPACTS AND IRREVERSIBLE OR IRRETRIEVABLE COMMITMENTS OF RESOURCES

In order to insure attention to possible threats to environmental protection and enhancement, the National Environmental Policy Act requires within each environmental impact statement identification of any unavoidable adverse impacts of the proposed action and also a delineation of irreversible or irretrievable resource commitments required by the action. The potential unavoidable adverse impacts of BPA's proposed rates would include: (1) an increase in power costs to consumers, with low-income consumers being impacted more, in proportion to their income, than high-income consumers; (2) an approximate 1 to 2 percent increase in annual consumption of fuel oil and gas by 1994, above what would be consumed without an increase in BPA rates; and (3) increased costs to irrigators possibly resulting, in some cases, in the curtailment of marginal farming operations.

Since the proposed BPA rate increase will be at least partially passed on by customer utilities as higher retail rates, the price of electricity will be greater for the region's ultimate consumers with the rate increase than without it. To the extent that demand for electricity is inelastic, the increase in relative cost would result in more income being spent on electricity than if rates were not increased. As a result, less income would be available for alternative uses, possibly causing a reduction in savings and in the quantities of other goods and services that individuals and families would be able to purchase and consume. While this general effect would be true for all consumers, it would fall more heavily on low-income consumers because a higher proportion of their expenditures on electricity is for essential uses, thereby limiting their opportunities for conservation. In addition, in the short run the poor are not able to substitute other fuels, buy more efficient appliances, install insulation, or take other conservation measures as readily as high-income people in response to increased electric rates.

The primary impact resulting from increased consumption of fossil fuels would be the increased emission of particulates, nitrogen oxides, sulfur oxides, carbon monoxide, hydrocarbons, aldehydes, and various other organic compounds into the atmosphere. These emissions are potentially dangerous to humans, other animals, and plants, and can cause property damage when present in concentrated amounts. Most of the increased consumption of fossil fuels resulting from an increase in wholesale rates for electricity would be concentrated in the region's urban centers, intensifying the air pollution already existing in those areas and resulting in more severe adverse impacts on health and property. Bonneville could do very little to prevent these effects of its increased rates; however, other factors such as inadequate supplies of fossil fuels, higher prices, possible future rationing to eliminate nonessential uses, more stringent pollution control regulations, and improved technology would reduce their impact.

To the extent that the consumption of gas and oil is greater with an increase in BPA rates than without, a rate increase would accelerate the depletion of the Nation's and the world's supplies of those important materials. The additional gas and oil consumed would be irretrievably committed to that use.

CHAPTER IX

SHORT-TERM VERSUS LONG-TERM USE OF THE ENVIRONMENT

In order to insure a harmonious relationship between man and the environment for future as well as present generations, the National Environmental Policy Act requires a discussion of "the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity." The short-term environmental effects of BPA's proposed rate increase would be primarily economic. The higher costs of electricity would force consumers to devote a somewhat larger share of their incomes to energy purchases, leaving somewhat less to spend on other goods and services. Except in the case of consumers with very low incomes, this shift is not expected to be significant.

Most of the impacts of Bonneville's proposal would develop gradually over a relatively extended period of time. For example, the full effect of the proposed rate increase on power consumption is expected to be reached only after a period of 20 or so years. Consumers would gradually adjust to higher electricity rates by taking measures to restrict their use, or increase their efficiency of use, of electrical power. Consumers would have added incentive to place greater emphasis on energy efficiency when replacing energy consuming appliances such as freezers, ranges, water heaters, and so forth. Increased electricity costs would also enhance the economics of home weatherization for those home owners with electric heat.

Increases in the efforts of consumers to reduce their use of electricity would favorably impact the rate at which non-renewable resources such as coal, oil, gas, and uranium would be consumed for electricity production in the BPA service area. Furthermore, fewer resources (land, capital, manpower, etc.) would be required for the construction and operation of new generation facilities. Additionally, impacts stemming from the construction and operation of generating facilities could be forestalled. Since most new facilities are expected to be thermal facilities, impacts associated with the operation of such facilities (air and thermal pollution) could also be reduced. Furthermore, there would be long-term economic benefits associated with minimization of dependence of the Northwest on expensive thermal plants.

To the extent that increased electricity prices in the Northwest result in switchovers to other energy sources such as wood, gas, coal, and oil, there would be a depletion of fossil fuel reserves and an accompanying degradation of local air quality. The amount of switching associated with the proposal is not expected to be great, however, and the resultant impacts would be quite small. Furthermore, these would be likely to be more than offset by reductions in the use of such fuels for electricity production.

CHAPTER X

CONSULTATION AND COORDINATION

A. Consultation in the Development of the Proposal

On January 18, 1978, BPA published in the Federal Register (43 FR 2659) and in newspapers throughout the region a "Notice of Intent to Develop Revised Wholesale Power Rates." This notice was the first step in an extensive public involvement program intended to solicit early input in the formulation of the 1979 rate proposal. Approximately 70 letters were received from a broad spectrum of interests, offering a variety of helpful suggestions and comments. This BPA public involvment process with regard to the rate proposal will continue up until the rates are filed with the Federal Energy Regulatory Commission.

A series of briefings was held with interested groups and individuals on the development of rate alternatives during the month of June 1978. These briefings described the progress of BPA's deliberations in the development and analysis of alternatives leading to the selection of a proposal.

B. Coordination in the Review of the Draft Environmental Statement and Revision of the Proposed Rates

BPA announced in the Federal Register on March 31, 1978, (43 FR 13607) its "Intent to Prepare a Draft Environmental Impact Statement." This notice solicited input to the EIS preparation process so that concerns could be expressed at an early date and could be fully considered in the preparation of this draft statement. No responses were received.

A notice of the availability of the draft statement was placed in the Federal Register on August 25, 1978 (43 FR 38356) and in local news media; separate notices were given for the public comment forums.

In September 1978 Bonneville conducted a series of public information meetings on its draft rate proposal and on the Draft Rate EIS.

The Draft EIS was sent to the Federal, State, and local agencies and other groups listed below. The public was invited to comment on the draft at public meetings held as part of the public involvement program during November 1978 at eight locations throughout the region: Seattle, Spokane, Richland, and Wenatchee, Washington; Portland and Eugene, Oregon; Idaho Falls, Idaho; and Missoula, Montana.

Substantial public interest was indicated throughout the public involvement and environmental review process. Bonneville received over 300 letters including technical reports submitted by customer groups and interested governmental agencies.

Following completion of revised studies and assessment of comments, BPA announced a revised wholesale rate proposal in the Federal Register on July 17, 1979. Public meetings were held on July 31 and August 1 in various locations in the region to receive comments on the revised proposal. Bonneville received 67 written comments during the comment period which opened with publication of the Federal Register notice and officially closed August 16. BPA also met informally with various customer groups to discuss the proposal.

In addition to soliciting comments through its public involvement process, BPA employed the services of professional consultants to evaluate both its initial proposal and its revised proposal. The initial proposal was also evaluated by staff from the Department of Energy (DOE) and the revised proposal will be submitted to DOE later this fall. Numerous meetings were held between BPA staff and representatives from DOE throughout the rate review process.

Bonneville participated in hearings held on July 19, 1979, on the six ratemaking standards contained in the Public Utility Regulatory Policies Act of 1978. Bonneville used these standards as guidelines in its process of developing proposed new rates.

Agencies requested to comment on the Draft Environmental Statement were:

Federal Agencies:

Environmental Protection Agency
Council on Wage and Price Stability
Department of Agriculture-
  Rural Electrification Administration
  Economic Research Service
Department of Defense-
  Army Corps of Engineers
Department of Health, Education, and Welfare
Department of Housing and Urban Development

Others:

Washington Environmental Council
Idaho Environmental Council
Environmental Information Center
Sierra Club, Northwest Representative
Idaho Conservation League
League of Women Voters
Common Cause
Gray Panthers
Idaho Consumer Affairs
Energy Conservation Coalition
Eugene Future Power Committee
Eco-Alliance

Survival Center
Izaak Walton League
Northwest Environmental Defense Center
Natural Resources Defense Council
Environmental Defense Fund
WASHPIRG
OSPIRG
Friends of the Earth
New American Movement
Puget Sound Energy Needs Committee
Western Environmental Trade Association
RESOLVE
POWER
State Grange
Oregon Consumer League
Columbia Basin Development League
Industrial Energy Users Committee
Center for the Public Interest

APPENDIX A

EXISTING WHOLESALE POWER RATE SCHEDULES

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EXISTING WHOLESALE POWER RATE SCHEDULES

EFFECTIVE DECEMBER 20, 1974 TO DECEMBER 20, 1979

Schedule EC-6 - Wholesale Firm Power Rate. This schedule, the principal rate for BPA's utility customers, is a two-part demand-energy rate applicable to all utilities purchasing firm power and to all other nonindustrial customers. The provisions of this schedule are:

a. Summer-Winter Differential. EC-6 provides for higher monthly charges ($1.05 per kilowatt of billing demand and 1.9 mills per kilowatt-hour of energy) in the winter drawdown season (September 1 - March 31) than charges ($0.93 per kilowatt of billing demand and 1.0 mill per kilowatthour of energy) during the summer storage refill season (April 1 - August 31). Higher charges during the winter drawdown season are the result of higher energy and capacity requirements in the region. Additional storage capacity is required and additional thermal and hydro generation are needed to meet the higher winter peakloads.

b. Facilities Charge. There is a charge for certain transformation and other substation facilities provided by BPA. The monthly charge is based on the load-side voltage as follows: (a) $0.12 per kilowatt of billing demand for delivery when the load-side voltage is 100 kV to 500 kV and (b) $0.20 per kilowatt of billing demand for delivery when the load-side voltage is less than 100 kV. If BPA and the purchaser share ownership of the facilities, the monthly charge is one-half of the charge that would apply if BPA owned all of the facilities.

c. Annual Minimum Bill for Computed Demand Customers. Computed demand customers have some generation of their own. BPA agrees to meet that portion of the computed demand customer's system requirements which exceed the assured firm capability of the customers resources. BPA requires a computed demand customer to pay a demand charge which is not less than 60 percent of his highest computed demand during the preceding 11 months. To assure recovery of the costs of serving these customers, BPA requires the computed demand customer to pay a minimum bill of $10.80 for each kW of the highest computed demand during the operating year. (See BPA, 1977, Appendix C, p. II-52).

d. Irrigation Discount and Developmental Discount Declining Credit. The irrigation and developmental discounts began being phased out in 1974. In order to ease the impact on customers who had previously had either or both discounts, a declining credit was established for the years 1975, 1976, 1977, 1978, and 1979. The billing modification for the discount is described in "Wholesale Power Rate Schedules and General Rate Schedule Provisions" under schedule EC-6, section 6.

e. Allocation of Energy by Administrator. Beginning in 1983-84, net requirements of preference customers will no longer be met by BPA as they have been in the past. Energy allocations will be determined at some point in the future and set forth in customers' contract provisions.

f. Unauthorized Increase (Overrun). This charge is designed to discourage the taking of power in excess of contracted amounts. An overrun is considered to be power taken in excess of the sum of the contract demand with BPA and contractual purchases from other suppliers. Each overrun is billed at $0.10 per kilowatthour.

g. Power Factor Adjustment. Schedule EC-6 provides for an adjustment in the power factor, the ratio of actual power to apparent power. In 1977, power factor adjustments were made for average power factors less than 90 percent. Presently, adjustments are made for average power factors less than 95 percent. The adjustment is made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor supplied during the month is less than the specified percent.

Schedule EC-7 - Reserve Power Rate. This schedule, serving preference public utilities, private utilities, and State and Federal agencies, is designed to be used primarily beginning in fiscal year 1983-84, the first year that allocations by BPA will be in effect. The initial rate is designed to be approximately 25 percent higher than the estimated cost of new thermal generation coming on line in 1983-84 and in subsequent years. Public agencies may purchase from BPA their requirements in excess of the allocation of power under the EC-6 rate schedule plus whatever amounts they have contracted to be supplied from new thermal plants. Private utilities may purchase load growth reserves in order to meet unanticipated load growth. The EC-7 schedule can also be used to serve a purchaser's firm power loads in circumstances where the Administrator does not have a Power Sales Contract in force with the purchaser. The provisions of this schedule are:

a. Summer-Winter Differential. The demand charge for the winter period (September 1 - March 31), is $1.65 per kilowatt of billing demand and the energy charge is 10.0 mills per kilowatthour. The demand charge for the summer storage refill season (April 1 - August 31), is $1.40 per kilowatt of billing demand and the energy charge is 5.0 mills per kilowatthour. The rates are higher than those found in schedule EC-6 to account for the higher costs of thermal generation in both summer and winter. Detailed analysis of the EC-7 schedule will be conducted prior to 1983-84 when the EC-7 rate will generally become applicable to preference customers.

b. Facilities Charge. The facilities charge for schedule EC-7 is the same as that found in the description of the facilities charge under schedule EC-6.

c. Unauthorized Increase (Overrun). See the description of Unauthorized Increase (Overrun) under schedule EC-6.

d. Power Factor Adjustment. Average power factor, the ratio of actual power to apparent power, must be 95 percent. If it is less, the measured demand is increased by 1 percent for each percent or major fraction thereof that the power factor is less than 95 percent.

Schedule IF-1 - Wholesale Power Rate for Industrial Firm Power IF-1, a two part firm rate, is the principal industrial rate. Customers taking power under IF-1 are subject to curtailment up to 25 percent of contract capacity at any time and to additional curtailment in varying degrees and for various reasons. The provisions of this schedule are:

a. Adjustments to Rate Based on Annual Availability Being Less Than 100 Percent. Since there is reduced assurance of delivering contract demand 100 percent of the time, credit is given for interruptions in availability. BPA annually determines what the percent of availability of power has been for a year (July-June) and applies credit under a schedule to the June power bill. If availability is less than 100 percent but 95 percent or higher, a credit of $2.00 per kilowatt of demand is applied. As percent of availability declines, the size of the credit increases to a maximum of $9.00 per kilowatt of demand when availability is less than 70 percent.

b. Charges for Demand and Energy. For industrial customers with at-site deliveries, the demand charge is $0.90 per month per kilowatt of billing demand. Other customers pay a demand charge of $1.20 per kW of billing demand. All IF-1 customers pay an energy charge of 1.525 mills per kWh.

c. The Availability of Authorized Increase. If an industrial customer wishes to increase its contract demand, it can apply in writing to the Administrator. If BPA cannot meet the request for additional firm power, the Administrator may still permit an authorized increase. The authorized increase would be billed under the IF-1 rate, but the amount of the authorized increase actually delivered would be determined separately on the basis of availability.

d. Summer-Winter Differentials Not Applied. BPA's industrial customers operate at a very high load factor throughout the year. As a result, the cost of serving these customers is no higher in winter than in summer so that the summer-winter differential is not applied.

e. Unauthorized Increase (Overrun). In the event that a customer's load exceeds his contract demand for industrial firm power plus any authorized increase, the excess is billed at the rate of $0.10 per kilowatthour.

f. Power Factor Adjustment. See the description of Power Factor Adjustment under schedule EC-6.

Schedule MF-1 - Wholesale Power Rate for Firm Power and Modified Firm Power. Schedule MF-1 is provided for industrial customers that wish to purchase firm power or modified firm power on a contract demand basis until existing contracts expire. The provisions of this schedule are:

a. Provision for Authorized Increase. An industrial customer may apply to BPA for an authorized increase and, if approved by the Administrator, the authorized increase will be billed under the firm power rate schedule and be adjusted in accordance with the availability schedule.

b. Charges for Demand and Energy. The monthly rate for firm power is $1.20 per kilowatt of contract demand and 1.525 mills per kilowatthour. For modified firm power, the demand charge is $1.15 per kilowatt of contract demand and 1.525 mill per kilowatthour. No summer-winter differential is applied. A credit of $0.30 per kilowatt of contract demand is given customers for at-site deliveries of firm power, modified firm, or authorized increase.

c. Adjustment to Rate Based on Annual Availability of Authorized Increase Power Being Less Than 100 Percent. For availability less than 100 percent but at least 95 percent, the annual credit is $2.00 per kilowatt of authorized increase applied to the June power bill. As percent of availability declines, the size of the credit increases to a maximum of $9.00 per kilowatt when availability is less than 70 percent.

d. Unauthorized Increase (Overrun). See the description of Unauthorized Increase (Overrun) under schedule IF-1.

e. Power Factor Adjustment. See the description of Power Factor Adjustment under schedule EC-6.

Schedule F-6 - Wholesale Firm Capacity Rate. This schedule is utilized by customers who are deficient in peak capacity but have adequate energy supplies. Firm capacity is available on a contract demand basis during a contract year, or during a contract season of June 1 through October 31. The provisions of this schedule are:

a. Basic Charge. The charge is $12 per kilowatt if the customer contracts for a year of contract demand. Interim (monthly) billing is $1.00 per kilowatt of contract demand per month. The charge is $6.50 per kilowatt of contract demand for the contract season, June 1 - October 31. Interim bills at the rate of $1.30 per kilowatt of contract demand are determined monthly.

b. Facilities Charge. The same facilities charge that applies to schedules EC-6 and EC-7 applies to schedule F-6.

c. Energy Replacement. Any energy (kilowatthours) associated with supplying firm capacity must be returned by the purchaser to BPA.

Schedule J-1 - Wholesale Firm Energy Rate. This schedule is available to all customers for contract purchase of firm energy only. Energy is contracted under this schedule for specific uses and periods of time at a charge of 4.0 mills per kilowatthour. Delivery of energy is assured during the contract year but delivery can be interrupted if system operating conditions require it.

Schedule H-5 - Wholesale Nonfirm Energy Rate. This schedule is available for the purchase of nonfirm energy, primarily as a replacement for energy supplied by thermal plants. The charge is 3.5 mills per kilowatthour during the period of September 1 - March 31 and 3.0 mills per kilowatthour during the period of April 1 - August 31. If a surplus remains after supplying the replacement needs within the Pacific Northwest, the surplus may be sold outside the region.

APPENDIX B

PROPOSED WHOLESALE POWER RATE SCHEDULES

I. Proposed Rate Schedules and General Rate Schedule Provisions

A. SCHEDULE EC-8 - WHOLESALE FIRM POWER RATE

Section 1. Availability: This schedule is available for the purchase of firm power for resale or for direct consumption by purchasers other than direct-service industrial purchasers which purchase power under rate Schedules IF-2 or MF-2.

Section 2. Rate:

a. Demand Charge: (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $1.95 per kilowatt of billing demand; (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.19 per kilowatt of billing demand; and (3) all other hours: No demand charge.

b. Energy Charge: (1) for the billing months September through March: 4.13 mills per kilowatthour of billing energy; (2) for the billing months April through August: 3.76 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The factors to be used in determining the billing for firm power purchased under this schedule are as follows:

a. For any purchaser not designated to purchase under subsection 3b or 3c: (1) the contract demand as specified in the contract; (2) the measured demand for the billing month adjusted for power factor; and (3) the measured energy for the billing month.

b. For any purchaser designated by Bonneville to purchase on a computed demand basis because of such purchaser's potential ability either to sell generation from its resources in such a manner as to increase Bonneville's obligation to deliver firm power to such purchaser in an amount in excess of Bonneville's obligation prior to such sale, or to redistribute the generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal System; provided, however, that when a purchaser operates two or more separate systems, only those systems designated by Bonneville will be covered by this subsection:

(1) the peak computed demand for the billing month; (2) the average energy computed demand for the billing month; (3) 60 percent of the highest peak computed demand during the previous 11 billing months; (4) 60 percent of the highest average energy computed demand for the previous 11 billing months; (5) the measured demand for the billing month adjusted for power factor; (6) the measured energy for the billing month; and (7) the contract demand as specified in an agreement between a purchaser and Bonneville for a specified period of time.

c. For any purchaser contractually limited to an allocation of capacity and/or energy as determined by Bonneville pursuant to the terms of a purchaser's power sales contract: (1) the allocated demand for the billing month, as specified in the contract; (2) the measured demand for the billing month adjusted for power factor; (3) the allocated energy for the billing month, as specified in the contract; (4) the measured energy for the billing month.

Section 4. Determination of Billing Demand and Billing Energy:

a. For a purchaser governed by subsection 3a:

(1) The billing demand for the month shall be factor 3a(1) or 3a(2), as specified in the purchaser's power sales contract, except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2), provided, however, that billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).

(2) The billing energy for the month shall be factor 3a(3) except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3).

b. For a purchaser governed by subsection 3b:

(1) the billing demand for the month shall be the largest of factors 3b(3), 3b(4), and 3b(5), or 3b(7) if applicable. Factor 3b(5), before adjustment for power factor, shall not exceed the largest of factors 3b(1), 3b(2), or 3b(7) if applicable, except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing demand for the month shall be factor 3c(2), provided, however, that billing demand factor 3c(2), before adjustment for power factor, shall not exceed factor 3c(1).

(2) the billing energy for the month shall be factor 3b(6) except that at such time as Bonneville determines that the limitation in section 3c is necessary, the billing energy shall be factor 3c(4), provided, however, that factor 3c(4) shall not exceed factor 3c(3). Factor 3b(6) shall not exceed factor 3b(2) times the number of hours during such month.

Section 5. Adjustments:

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. At-Site Power: At-site power purchased for consumption by a purchaser shall be used within 15 miles of the powerplant specified in the power sales contract. At least 90 percent of any at-site power purchased for resale shall be used within 15 miles of the specified powerplant.

The monthly demand charge for at-site firm power will be the monthly demand charge for firm power reduced by $0.257 per kilowatt of billing demand.

At-site firm power is made available only under existing contracts, providing for at-site firm power, at a Federal hydroelectric generating plant or at a point adjacent thereto, and at a voltage, all as designated by Bonneville. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by Bonneville. This use of facilities charge shall be in addition to the charge determined by application of section 2 of the rate schedule as reduced by the provisions of this subsection.

Section 6. Unauthorized Increase: That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from Bonneville) that cannot be assigned to a class of power which Bonneville delivers on such hour pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which Bonneville delivers during such month pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such month, may be considered an unauthorized increase. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be $0.10 per kilowatthour.

Section 7. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

B. SCHEDULE EC-9 - RESERVE POWER RATE

Section 1. Availability: This schedule is available for the purchase of:

a. firm power to meet a purchaser's unanticipated load growth as provided in a purchaser's power sales contract.

b. power for which Bonneville determines no other rate schedule is applicable; or,

c. power to serve a purchaser's firm power loads in circumstances where Bonneville does not have a power sales contract in force with such purchaser, and Bonneville determines that this rate should be applicable.

Section 2. Rate:

a. Demand Charge: (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $6.16 per kilowatt of billing demand; (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $3.76 per kilowatt of billing demand; and (3) all other hours: no demand charge.

b. Energy Charge: 26.7 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The factors to be used in determining the billing for power purchased under this schedule are as follows:

a. The contract demand as specified in the contract.

b. The measured demand.

c. The contract amount of energy for the month.

d. The measured energy for the month.

Section 4. Determination of Billing Demand and Billing Energy: The billing demand and billing energy shall be determined as provided in a purchaser's power sales contract. If Bonneville does not have a power sales contract in force with a purchaser, the billing demand and billing energy shall be the measured demand adjusted for power factor and measured energy.

Section 5. Unauthorized Increase: That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from Bonneville) that cannot be assigned to a class of power which Bonneville delivers on such hour pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which Bonneville delivers during such month pursuant to contracts between Bonneville and the purchaser or to a type of power which the purchaser acquires from sources other than Bonneville which Bonneville delivers during such month, may be considered an unauthorized increase. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be $0.10 per kilowatthour.

Section 6. Power Factor Adjustment: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

Section 7. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

C. SCHEDULE IF-2 - WHOLESALE POWER RATE FOR INDUSTRIAL FIRM POWER

Section 1. Availability: This schedule is available for the purchase of industrial firm power and/or authorized increase on a contract demand basis and for additional power requested by the purchaser and made available as authorized increase by Bonneville on an intermittent basis.

Section 2. Rate:

a. Demand Charge: (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $1.95 per kilowatt of billing demand; (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.19 per kilowatt of billing demand; and (3) all other hours: no demand charge.

b. Energy Charge: (1) for the billing months September through March: 4.13 mills per kilowatthour of billing energy; (2) for the billing months April through August: 3.76 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The factors to be used in determining the billing for power purchased under this rate schedule are as follows: (a) contract demand, (b) curtailed demand, (c) restricted demand, and (d) measured energy.

Section 4. Determination of Billing Demand and Billing Energy: The billing demands for industrial firm power and authorized increase, respectively, and for additional power requested by the purchaser and made available by Bonneville as authorized increase on an intermittent basis will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed porportionately among the respective demands for each hour each such demand is applicable during the billing month.

Section 5. Adjustments:

a. Availability Credit: If Bonneville restricts deliveries to the purchaser for any purpose other than scheduled maintenance or forced outages on either the purchaser's system or Bonneville's delivery facilities, then the purchaser will be entitled to an annual billing credit for such restriction. For periods beginning July 1 and ending June 30 (operating year), such credit will be the product of one-twelfth of the sum of the monthly billing demands and the value of the availability credit factor (determined from the appropriate formula below). An appropriate adjustment shall be made to the purchaser's December wholesale power bill based on calculated availability during the first six months of the operating year. A final adjustment, when appropriate, shall be made to the purchaser's June wholesale power bill for availability credits calculated on an annual basis, giving consideration for those credits granted on the purchaser's December wholesale power bill. For periods which do not correspond to an operating year, the sum of the monthly billing demands during the period will be divided by the number of months in the period and then multiplied by the appropriate availability credit factor calculated for such periods. An appropriate adjustment will be made at the earliest practical time. Availability credits will be separately determined for industrial firm power and authorized increases. Availability credits will not apply to additional power made available as authorized increase on an intermittent basis.

Annual Availability A		Formula for availability credit factor F
greater than	but less than or equal to	
.75	1.00	F = $56 (1-A)
.0	.75	F = $14.00

b. <u>Power Factor</u>: The adjustment for power factor, when specified in this rate schedule or power sales contract, may be made by increasing the appropriate demand (contract, curtailed, or restricted) for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95, percent such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

c. <u>At-Site Power</u>: At-site industrial firm power shall be used within 15 miles of the powerplant.

The monthly demand charge for at-site industrial firm power will be the monthly demand charge for industrial firm power reduced by $0.257 per kilowatt of billing demand.

At-site industrial firm power is made available only under existing contracts, providing for at-site industrial firm power at a Federal hydroelectric generating plant or at a point adjacent thereto, and at a voltage, all as designated by Bonneville. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by Bonneville. This use of facilities charge shall be in addition to the charge determined by application of section 2 of the rate schedule as reduced by the provisions of this subsection.

Section 6. Unauthorized Increase: Any amount by which any 60-minute clock-hour integrated demand exceeds the sum of the billing demand for such hour before adjustment for power factor, plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of $0.10 per kilowatthour.

Section 7. Special Conditions - Advance of Energy: Bonneville may elect to advance energy under terms and conditions of the purchaser's power sales contract.

Section 8. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

D. SCHEDULE MF-2 - WHOLESALE POWER RATE FOR MODIFIED FIRM POWER

Section 1. Availability: This schedule is available for the purchase of modified firm power on a contract demand basis for direct consumption by existing direct-service industrial customers until existing contracts terminate. This schedule is also available for the purchase of authorized increase power on a contract demand basis and for additional power requested by the purchaser and made available by Bonneville as authorized increase on an intermittent basis.

Section 2. Rate:

a. Demand Charge: (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: $1.95 per kilowatt of billing demand; (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: $1.19 per kilowatt of billing demand; and (3) all other hours: no demand charge.

b. Energy Charge: (1) for the billing months September through March: 4.13 mills per kilowatthour of billing energy; (2) for the billing months April through August: 3.76 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The factors to be used in determining the billing for power purchased under this rate schedule are as follows: (a) contract demand, (b) curtailed demand, (c) restricted demand, and (d) measured energy.

Section 4. Determination of Billing Demand and Billing Energy: The billing demand for modified firm power and authorized increase, respectively, and for additional power requested by the purchaser and made available by Bonneville on an intermittent basis will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed proportionately among the respective demands for each hour each such demand is applicable during the billing month.

Section 5. Adjustments:

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or power sales contract, shall be made by increasing the appropriate demand (contract, curtailed, or restricted) for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. At-Site Power: At-site modified firm power shall be used within 15 miles of the powerplant.

The monthly demand charge for at-site modified firm power will be the monthly demand charge for modified firm power reduced by $0.257 per kilowatt of billing demand.

At-site modified firm power will be made available under existing contracts, providing for at-site modified firm power at a Federal hydroelectric generating plant or at a point adjacent thereto, and at a voltage, all as designated by Bonneville. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by Bonneville. This use of facilities charge shall be in addition to the charge determined by application of section 2 of the rate schedule as reduced by the provisions of this subsection.

Section 6. Unauthorized Increase: Any amounts by which any 60-minute clock-hour integrated demand exceeds the sum of the billing demand for such hour (before adjustment for power factor) plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of $0.10 per kilowatthour.

Section 7. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

E. SCHEDULE F-7 - WHOLESALE FIRM CAPACITY RATE

Section 1. Availability: This schedule is available for the purchase of firm capacity without energy on a contract demand basis for supply during a contract year of 12 months, or during a contract season of 5 months, June 1 through October 31.

Section 2. Rate:

a. Contract Year Service: $18.84 per kilowatt per year of contract demand. Interim bills will be rendered monthly at the rate of $1.57 per kilowatt of contract demand.

b. Contract Season Service: $9.73 per kilowatt per season of contract demand. Interim bills will be rendered monthly at the rate of $1.946 per kilowatt of contract demand.

c. The capacity rate specified in subsections a. and b. above shall be increased by $0.265 per kilowattmonth of billing demand for each hour that the purchaser's monthly demand duration exceeds 6 hours. The purchaser's demand duration for the month shall be determined by dividing the kilowatthours supplied under this rate schedule to a purchaser on the day of maximum kilowatthour use between the hours of 7 a.m. and 10 p.m., excluding Sundays, by the purchaser's contract demand effective for such month. If, however, Bonneville does not require the delivery of peaking replacement energy by the purchaser during certain periods, the additional charge above will not be made for such periods.

Section 3. Billing Factors: The billing demand will be the contract demand.

Section 4. Special Provision: Contracts for the purchase of firm capacity under this schedule will include provisions for replacement by the purchaser of energy accompanying the delivery of such capacity.

Section 5. General Provisions: Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

SCHEDULE F-8 - EMERGENCY CAPACITY RATE

Section 1. Availability: This schedule is available for purchase of emergency capacity requested by a purchaser when Bonneville determines that an emergency condition exists on the purchaser's system and it has capacity available for such purpose.

Section 2. Rate: $0.42 per kilowatt of demand per calendar week or portion thereof. For deliveries over the Pacific Northwest-Pacific Southwest intertie, made available for the account of a purchaser at the Oregon-California or the Oregon-Nevada border, the charge will be increased by $0.086 per kilowatt. Bills will be rendered monthly.

Section 3. Billing Factors: The billing demand will be the maximum amount requested by the purchaser and made available by Bonneville during a calendar week, provided that if Bonneville is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, such billing demand for such week shall be the lower demand which Bonneville is able to supply.

Section 4. Special Provision: Energy delivered with such capacity shall be returned to Bonneville within 7 days of the date of delivery at times and rates of delivery agreed to by the purchaser and Bonneville prior to delivery. Bonneville may agree to accept delay of return energy beyond 7 days if it so agrees prior to the delivery of capacity.

F. SCHEDULE J-2 - WHOLESALE FIRM ENERGY RATE

Section 1. Availability: This schedule is available for contract purchase of firm energy, to be delivered for the uses, in the amounts, and during the period or periods specified in such contract.

Section 2. Rate: 6.1 mills per kilowatthour of billing energy.

Section 3. Billing Factors: The contract energy is the billing factor.

Section 4. Determination of Billing Energy: The billing energy shall be determined as provided in the purchaser's power sales contract.

Section 5. Delivery: Delivery of energy under this rate schedule is assured during the contract period. However, Bonneville may interrupt the delivery of firm energy hereunder, in whole or in part, at any time that Bonneville determines that Bonneville is unable because of system operating conditions, including lack of generation or transmission capacity, to effect such delivery.

Section 6. Power Factor Adjustment: The adjustment for power factor, when specified in this rate schedule or power sales contract, may be made by increasing the contract energy delivered for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by Bonneville. Unless specifically otherwise agreed, Bonneville may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to the purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

Section 7. General Provisions: Sales of energy under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

G. SCHEDULE H-6 - WHOLESALE NONFIRM ENERGY RATE

Section 1. Availability: This schedule is available for the purchase of nonfirm energy both inside and outside the Pacific Northwest. This schedule is also available for energy delivered for emergency use under the conditions set forth in section 5.1 of the General Rate Schedule Provisions. This schedule is not available for the purchase of energy which Bonneville has a firm obligation to supply.

Section 2. Rate:

a. Thermal Displacement - This rate is for nonfirm energy sales to any purchaser for displacement of thermal generation. When Bonneville determines that nonfirm energy is available, such energy shall be offered to displace the thermal generation and firm purchases of thermal energy, consistent with Public Law 88-552 and other applicable statutes.

(1) For all nonfirm energy sales for thermal displacement not subject to the provisions of a.(2) below the rate is fifty percent of either (a) the decremental cost in mills per kilowatthour of the displaced thermal resource or (b) the rate in mills per kilowatthour associated with the displaced firm purchase of thermal energy. The maximum charge is 20 mills per kilowatthour. The minimum charge is 6.5 mills per kilowatthour during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m.; and 4.5 mills per kilowatthour for all other hours of the year. Bonneville may determine that because of water and market conditions a rate of less than 50 percent of decremental cost or purchase rate, but not less than the minimum rates, may be charged. The purchaser will furnish Bonneville with either (a) the decremental cost in mills per kilowatthour of the purchaser's displaced thermal resource or (b) the rate in mills per kilowatthour associated with the displaced firm purchase of thermal energy.

(2) For nonfirm energy sales to any Pacific Northwest utility during the period when that utility is either operating a displaceable thermal resource or is purchasing firm energy from a thermal resource and is concurrently selling nonfirm energy outside the Pacific Northwest, as defined in Public Law 88-552, the rate is:

Thirty-three percent of the rate in mills per kilowatthour that the purchaser receives for concurrent nonfirm energy sales for use outside the Pacific Northwest. The maximum charge is 20 mills per kilowatthour. The minimum charge is 6.5 mills per kilowatthour during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m.; and 4.5 mills per kilowatthour for all other hours of the year. The purchaser will furnish Bonneville with the amount and rate per kilowatthour for the purchaser's sale of nonfirm energy for use outside the Pacific Northwest for the period when nonfirm energy purchases are made from Bonneville.

b. Sales other than for Thermal Displacement - This rate is for all nonfirm energy sales which are not applicable to the provisions of a. above.

(1) 6.5 mills per kilowatthour during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m.; and

(2) 4.5 mills per kilowatthour for all hours of the year not included in subsection b(1) above.

c. For contracts which refer to this schedule for determining the value of energy, the rate is 5.5 mills per kilowatthour.

Section 3. <u>Delivery</u>: Bonneville shall determine the availability of energy hereunder and the rate of delivery thereof.

Section 4. <u>General Provisions</u>: Sales of energy under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, and to the applicable General Rate Schedule Provisions.

H. GENERAL RATE SCHEDULE PROVISIONS

1.1 <u>Firm Power</u>: Firm power is electric power which Bonneville will make continuously available to a purchaser to meet its load requirements except when restricted because the operation of generation or transmission facilities used by Bonneville to serve such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract. Such restriction of firm power shall not be made until industrial firm power has been restricted in accordance with section 1.4 and until modified firm power has been restricted in accordance with section 1.2.

1.2 <u>Modified Firm Power</u>: Modified firm power is electric power which Bonneville will make continuously available to a purchaser on a contract demand basis subject to: (a) the restriction applicable to firm power, and (b) the following:

When a restriction is made necessary because the operation of generation or transmission facilities used by Bonneville to serve such purchaser and one or more firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract, Bonneville shall restrict such purchaser's contract demand for modified firm power to the extent necessary to prevent, if possible, or minimize restriction of any firm power, provided, however, that: (1) such restriction of modified firm power shall not exceed at any time 25 percent of the contract demand therefor, and (2) the accumulation of such restrictions of modified firm power during any calendar year, expressed in kilowatthours, shall not exceed 500 times the contract demand therefor. When possible, restrictions of modified firm power will be made ratably with restrictions of industrial firm power based on the proportion that the respective contract demands bear to one another. The extent of such restrictions shall be limited for modified firm power by this subsection and for industrial firm power by the Restriction of Deliveries Section of the General Contract Provisions of the contract.

1.3 Firm Capacity: Firm capacity is capacity which Bonneville assures will be available to a purchaser on a contract demand basis except when operation of generation or transmission facilities used by Bonneville to serve such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

1.4 Industrial Firm Power: Industrial firm power is electric power which Bonneville will make continuously available to a purchaser on a contract demand basis subject to: (a) the restriction applicable to firm power, and (b) the following:

(1) The restrictions given in the Restriction of Deliveries Section of the General Contract Provisions of the contract.

(2) When a restriction is made necessary because of the operation of generation or transmission facilities used by Bonneville to serve such purchaser and one or more firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract, Bonneville shall restrict such purchaser's contract demand for industrial firm power to the extent necessary to prevent, if possible, or minimize restriction of firm power. When possible, restrictions of industrial firm power will be made ratably with restrictions of modified firm power based on the proportion that the respective contract demands bear to one another. The extent of such restrictions shall be limited for modified firm power by section 1.2 (b) of these General Rate Schedule Provisions and for industrial firm power by the Restriction of Deliveries Section of the General Contract Provisions of the contract.

1.5 Authorized Increase: An authorized increase is an amount of electric power specified in the contract in excess of the contract demand for firm power, modified firm power, or industrial firm power that Bonneville may be able to make available to the purchaser upon its request. The purchaser shall make such request in writing stating the amount of increase requested, the purpose for which it will be used, and the period for which it is needed. Such request shall be made prior to the first calendar month beginning such specified period. Bonneville will then determine whether such increase can be made available, but it shall retain the right to restrict the delivery of such increase if it determines at any subsequent time that such increase will no longer be available.

The purchaser may curtail an authorized increase, in whole or in part, at the end of any billing month within the period such authorized increase is to be made available.

1.6 Firm Energy: Firm energy is energy which Bonneville assures will be available to a purchaser during the period or periods specified in the contract except during such hours as specified in the contract and when the operation of the Government's facilities used to serve the purchaser are suspended, interrupted, interfered with, curtailed, or restricted by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

2.1 Contract Demand: The contract demand shall be the number of kilowatts that the purchaser agrees to purchase and Bonneville agrees to make available. Bonneville may agree to make deliveries at a rate in excess of the contract demand at the request of the purchaser (authorized increase), but shall not be obligated to continue such excess deliveries.

2.2 Measured Demand: Except where deliveries are scheduled as hereinafter provided, the measured demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands at which electric energy is delivered to a purchaser at each point of delivery during each time period specified in the applicable rate schedule during any billing period. Such largest 60-minute integrated demand shall be determined from measurements made as specified in the contract, or as determined in section 3.2 herein. Bonneville, in determining the measured demand, will exclude any abnormal 60-minute integrated demands due to or resulting from (a) emergencies or breakdowns on, or maintenance of, the Federal System facilities, and (b) emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by Bonneville. For those contracts to which Bonneville is a party and which provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute integrated demand assigned to any class of power shall be determined as specified in the contract. The portion of the total measured demand so assigned shall constitute the measured demand for each such class of power.

If the flow of electric energy to a purchaser's system through two or more points of delivery cannot be adequately controlled because such points are interconnected within the purchaser's system, or the purchaser's system is interconnected directly or indirectly with the Federal System, the purchaser's measured demand for each class of power for such system for any billing period shall be the largest of the hourly amounts of such class of power which are scheduled for delivery to the purchaser during each time period specified in the applicable rate schedule.

2.3 Peak Computed Demand and Energy Computed Demand: The purchaser's peak computed demand for each billing month shall be the largest amount during such month by which the purchaser's 60-minute system demand exceeds its assured peaking capability.

The purchaser's average energy computed demand for each billing month shall be the amount during such month by which the purchaser's actual system average load exceeds its assured average energy capability.

a. General Principles:

(1) The assured peaking and average energy capability of each of the purchaser's systems shall be determined and applied separately.

(2) As used in this section, "year" shall mean the 12-month period commencing July 1.

(3) The critical period is that period, determined for the purchaser's system under adverse streamflow conditions adjusted for current water uses, assured storage operation, and appropriate operating agreements, during which the purchaser would have the maximum requirement for peaking or energy after utilizing the firm capability of all resources available to its system in such a manner as to place the least requirement for capacity and energy on Bonneville.

(4) Critical water conditions are those conditions of streamflow based on historical records, adjusted for current water uses, assured storage operation, and appropriate operating agreements, for the year or years which would result in the minimum capability of the purchaser's firm resources during the critical period.

(5) Prior to the beginning of each year the purchaser shall determine the assured capability of each of the purchaser's systems in terms of peaking and average energy for each month of each year or years within the critical period. The firm capability of all resources available to the purchaser's system shall be utilized in such a manner as to place the least requirement for capacity and energy on Bonneville. Such assured capability shall be effective after review and approval by Bonneville.

(6) The purchasers's assured energy capability shall be determined by shaping its firm resources to its firm load in a manner which places a uniform requirement on Bonneville within each year of the critical period with such requirement increasing each year not in excess of the purchaser's annual load growth.

(7) As used herein, the capability of a firm resource shall include only that portion of the total capability of such resource which the purchaser can deliver on a firm basis to its load. The capabilities of all generating facilities which are claimed as part of the purchaser's assured capability shall be determined by test or other substantiating data acceptable to Bonneville. Bonneville may require verification of the capabilities of any or all of the purchaser's generating facilities. Such verification will not be required more often than once each year for operating plants, or more often than once each third year for thermal plants in cold standby status, if Bonneville determines that adequate annual preventive maintenance is performed and the plant is capable of operating at its claimed capability.

(8) In determining assured capability, the aggregate capability of the purchaser's firm resources shall be appropriately reduced to provide adequate reserves.

b. Determination of Assured Capability: The purchaser's assured peaking and energy capabilities shall be the respective sums of the capabilities of its hydroelectric generating plants based on the most critical water conditions on the purchaser's system, the capabilities of its thermal generating plants based on the adverse fuel or other conditions reasonably to be anticipated; and the firm capabilities of other resources made available under contracts prior to the beginning of the year, after deduction of adequate reserves. Assured capabilities shall be determined for each month if the purchaser has seasonal storage. The capabilities of the purchaser's firm resources shall be determined as follows:

(1) Hydroelectric Generating Facilities: The capability of each of the purchaser's hydroelectric generating plants shall be determined in terms of both peaking and average energy using critical water conditions. The average energy capability shall be that capability which would be available under the storage operation necessary to produce the claimed peaking capability.

Seasonal storage shall mean storage sufficient to regulate all the purchaser's hydroelectric resources in such a manner that when combined with the purchaser's thermal generating facilities, if any, and with firm capacity and energy available to the purchaser under contracts, a uniform energy computed demand for a period of 1 month or more would result.

A purchaser having seasonal storage shall, within 10 days after the end of each month in the critical period, notify Bonneville in writing of the assured energy capability to be applied tentatively to the preceding month; such notice shall also specify the purchaser's best estimate of its average system energy load for such month. If such notice is not submitted, or is submitted later than 10 days after the end of the month to which it applies, subject to the limitations stated herein, the assured energy capability determined for such month prior to the beginning of the year shall be applied to such month and may not be changed thereafter.

If notice has been submitted pursuant to the preceding paragraph, the purchaser shall, within 30 days after the end of the month, submit final specification of the assured energy capability to be applied to the preceding month; provided that the assured energy capability so specified shall not differ from the amount shown in the original notice by more than the amount by which the purchaser's actual average system energy load for such month differs from the estimate of that load shown in the original notice. If the assured energy capability for such month differs from that determined prior to the beginning of the year for such month, the purchaser, if required by Bonneville, shall demonstrate by a suitable regulation study based on critical water conditions that such change could actually be accomplished, and that the remaining balance of its total critical period assured energy capability could be developed without adversely affecting the firm capability of other purchaser's resources. The algebraic sum of all such changes in the purchaser's assured energy capability shall be zero at the end of the critical period or year, whichever is earlier. Appropriate adjustments in the assured peaking capability shall be made if required by any change in reservoir operation indicated by such revisions in the monthly distribution of critical period energy capability.

(2) Thermal Generating Facilities: The capability of each of the purchaser's thermal generating plants shall be determined in terms of both peaking and average energy. Such capabilities shall be based on the adverse fuel or other conditions reasonably to be anticipated. The effect of limitations on fuel supply due to war or other extraordinary situations will be evaluated at the time of occurrence.

(3) Other Sources of Power: The assured capability of other resources available to the purchaser on a firm basis under contracts shall be determined prior to each year in terms of both peaking and average energy.

c. Determination of Computed Demand: The purchaser's computed demand for each billing month shall be the greater of:

(1) The largest amount during such month by which the purchaser's actual 60-minute system demand, excluding any loads otherwise provided for in the contract, exceeds its assured peaking capability for such month, or period within such month, or

(2) The largest amount for such month, or period within such month, by which the purchaser's actual system average energy load, excluding the average energy loads otherwise provided for in the contract, exceeds its assured average energy capability.

The use of computed demands as one of the alternatives in determining billing demand is intended to assure that each purchaser who purchases power from Bonneville to supplement its own firm resources will purchase amounts of power substantially equivalent to the additional capacity and energy which the purchaser would otherwise have to provide on the basis of normal and prudent operations, viz, sufficient capacity and energy to carry the load through the most critical water or other conditions reasonably to be anticipated, with an adequate reserve.

Since the computed demand depends on the relationship of capability of resources to system requirements, the computed demand for any month cannot be determined until after the end of the month. As each purchaser must estimate its own load, and is in the best position to follow its development from day to day, it will be the purchaser's responsibility to request scheduling of firm power, including any increase over previously established demands, on the basis estimated by the purchaser to result in the most advantageous purchase of the power to be billed at the end of the month.

Each contract in which computed demand may be a factor in determining the billing demand shall have attached to it as an exhibit a sample calculation of the computed demand of the purchaser for the period having the highest computed demand during the 12 months immediately preceding the effective date of the contract.

2.4 Restricted Demand: A restricted demand shall be the number of kilowatts of firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results when Bonneville has restricted delivery of such power for 1 clock-hour or more. Such restrictions by Bonneville are made pursuant to section 8 of the General Contract Provisions for industrial firm power and pursuant to sections 1.1 and 1.2 of the General Rate Schedule Provisions for firm power and modified firm power, respectively. Such restricted demand shall be determined by Bonneville after the purchaser has made its determination to accept such restriction or to curtail its contract demand for the month in accordance with section 2.5 of the General Rate Schedule Provisions.

2.5 Curtailed Demand: A curtailed demand shall be the number of kilowatts of firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results from the purchaser's request for such power in amounts less than the contract demand therefor. Each purchaser of industrial firm power or modified firm power may curtail its demand in accordance with the section entitled "Curtailment of Deliveries and Payment Therefor" of the General Contract Provisions of the contract. Each purchaser of an authorized increase in excess of firm power, modified firm power, or industrial firm power may curtail its demand in accordance with section 1.5 of the General Rate Schedule Provisions.

3.1 Billing: Unless otherwise provided in the contract, power made available to a purchaser at more than one point of delivery shall be billed separately under the applicable rate schedule or schedules. The contract may provide for combined billing under specified conditions and terms when (a) delivery at more than one point is beneficial to Bonneville, or (b) the flow of power at the several points of delivery is reasonably beyond the control of the purchaser.

If deliveries at more than one point of delivery are billed on a combined basis for the convenience of the customer, a charge will be made for the diversity between the measured demands at the several points of delivery. The charge for the diversity shall be determined in a uniform manner among purchasers and shall be specified in the contract.

3.2 Determination of Estimated Billing Data: If the purchased amounts of capacity, energy, or the 60-minute integrated demands for energy must be estimated from data other than metered or scheduled quantities, Bonneville and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on the estimated billing quantities, a determination binding on both parties shall be made in accordance with the arbitration provisions of the contract.

4.1 Application of Rates During Initial Operation Period: For an initial operating period, not in excess of 3 months, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, Bonneville may agree (a) to bill for service to such new or reactivated plant facilities on the basis of the measured demand for each day, adjusted for power factor, or (b) if such facilities are served by a distributor purchasing power therefor from Bonneville, to bill for that portion of such distributor's load which results from service to such facilities on the basis of the measured demand for each day, adjusted for power factor. Any rate schedule provisions regarding contract demand, billing demand, and minimum monthly charge which are inconsistent with this section shall be inoperative during such initial operating period.

The initial operating period and the special billing provisions may, on approval by Bonneville, be extended beyond the initial 3-month period for such additional time as is justified by the developmental character of the operations.

5.1 Energy Supplied For Emergency Use: A purchaser taking firm power shall pay in accordance with Wholesale Nonfirm Energy Rate Schedule H-6 and emergency capacity Schedule F-8 for any electric energy which has been supplied (a) for use during an emergency on the purchaser's system, or (b) following an emergency to replace energy secured from sources other than Bonneville during such emergency, except that mutual emergency assistance may be provided and settled under exchange agreements.

6.1 Billing Month: Meters will normally be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less or more than the normal billing month, the monthly charges stated in the applicable rate schedule will be appropriately adjusted. Winter and summer periods identified in the rate schedules will begin and end with the beginning and ending of the purchaser's billing month having meter-reading dates closest to the periods so identified.

7.1 Payment of Bills: Bills for power shall be rendered monthly and shall be payable at Bonneville's headquarters. Failure to receive a bill shall not release the purchaser from liability for payment. Demand and energy billings under each rate schedule application shall be rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

If Bonneville is unable to render the purchaser a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of and be subject to the same repayment provisions as shall a final bill.

Bills not paid in full on or before the close of business of the 20th day after the date of the bill shall bear an additional charge which shall be the greater of one-fourth percent (0.25%) of the amount unpaid or $50. Thereafter a charge of one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph shall not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the 20th day after the date of the bill. If the 20th day after the date of the bill is a Sunday or other nonbusiness day of the purchaser, the next following business day shall be the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the 20th day must bear a postal department cancellation in order to avoid assessment of such further charges.

Bonneville may, whenever a power bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill, and after giving 30 days advance notice in writing, cancel the contract for service to the purchaser, but such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto.

8.1 Approval of Rates: Schedules of rates and charges, or modifications thereof, for electric energy sold by Bonneville shall become effective only after confirmation and approval by the entity or entities designated to confirm and approve such rates and charges by the Secretary of Energy.

9.1 Average Power Factor: The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovoltamperehours})^2}}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

When deliveries to a purchaser at any point of delivery include more than one class of power or are under more than one rate schedule, and it is impracticable to separately meter the kilowatthours and reactive kilovoltamperehours for each class, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for each of the separate classes of power and rate schedules.

10.1 Temporary Curtailment of Contract Demand: The reduction of charges for power curtailed pursuant to the purchaser's contract and Sections 1.5 and 2.5 hereof shall be applied in a uniform manner.

11.1 General Provisions: The Wholesale Rate Schedules and General Rate Schedule Provisions of the Bonneville Power Administration effective December 20, 1979, supersede in their entirety Bonneville's Wholesale Power Rate Schedules and General Rate Schedule Provisions effective December 20, 1974.

APPENDIX C

TYPICAL MONTHLY ELECTRIC BILLS

FOR PACIFIC NORTHWEST UTILITIES

TYPICAL

Monthly Electric Bills

FOR PACIFIC NORTHWEST UTILITIES

UNITED STATES DEPARTMENT OF ENERGY

BPA

BONNEVILLE POWER ADMINISTRATION

BONNEVILLE POWER ADMINISTRATION

DATE

June 1, 1979

INDEX PAGE

GENERAL NOTES

1. Computations are based on best available information at time of publication.

2. Local taxes are not included.

3. Primary service discount applied on loads of 500 kW and over where provided in rate schedule.

4. Lowest applicable rate used where optional rates are available.

5. If not stated otherwise, rates based on horsepower assume conversion factor of 1 h.p. = .75 kW.

6. All figures are dollars.

7. Rate Type: Each bill has been keyed according the following rate changes:

   Type EI - Each additional block of energy is sold at a lower rate.

   Type E2 - All energy is sold at one rate.

   Type E3 - Each additional block of energy is sold at a higher rate.

   Type E4 - Each additional block of energy is sold at a lower rate except for the final block.

   Type D - A portion of the bill is based on a kilowatt charge.

   Type C - The bill includes a specific monthly service charge.

TYPICAL MONTHLY ELECTRIC BILLS

RESIDENTIAL SERVICE

Municipalities	RATE TYPE	MINIMUM BILL	500 kwh	1000 kwh	2000 kwh
Albion, ID	E1	3.50	9.50	16.45	25.95
Ashland, OR	E4	2.15	11.36	18.67	34.97
Bandon, OR	E1	2.50	7.65	11.65	19.65
Blaine, WA	E3,C	3.00	9.00	15.00	27.80
Bonners Ferry, ID[1]	E2,C	1.80	7.85	13.90	26.00
Burley, ID	E1	3.15	9.18	15.25	27.41
Canby, OR	E2,C	4.50	9.50	14.50	24.50
Cascade Locks, OR (Local)	E1	4.50	8.64	13.82	24.17
(Rural)	E1	4.50	8.28	13.98	25.37
Centralia, WA	E1,C	2.25	7.40	12.55	22.85
Cheney, WA[2]	E3	4.00	8.00	13.00	23.00
Coulee Dam, WA	E1	3.50	8.75	12.90	18.40
Declo, ID	E1	3.00	11.97	17.15	27.50
Drain, OR	E2,C	2.50	7.50	12.50	22.50
Eatonville, WA	E1	3.00	10.34	16.39	28.49
Ellensburg, WA	E2[3]	3.00	6.00	12.00	24.00
	E2[4]	3.00	6.90	13.80	27.60
Eugene, OR	E2,C	3.40	10.37	17.33	31.26
Fircrest, WA	E1[6]	4.00	9.00	13.80	23.40
	E1	4.00	9.90	15.40	25.00
Forest Grove, OR	E2,C	2.00	7.00	12.00	22.00
Heyburn, ID	E1	2.00	10.00	15.05	23.55
Idaho Falls, ID	E1[7]	5.00	9.69	14.49	24.09
	E1	2.00	10.14	14.94	24.54
McCleary, WA	E1	4.00	7.00	10.75	18.25
McMinnville, OR	E2,C	3.00	8.00	13.00	23.00
Milton, WA	E2,C	4.00	10.25	16.50	29.00
Milton-Freewater, OR	E4	3.50	5.78	9.58	17.82
Minidoka, ID	E1	2.00	7.20	11.70	20.70
Monmouth, OR	E1	3.00	7.76	13.71	25.61
Port Angeles, WA	E4[6]	6.00	6.00	9.30	16.20
	E1	1.20	6.48	10.68	19.08
Richland, WA	E2,C	4.00	10.20	16.40	28.80
Richland, WA[5]	E2	--	5.58	11.16	22.32
Rupert, ID	E4	2.00	7.50	11.25	18.75
Seattle, WA[7]	E3,C[6]	1.50	5.44	10.39	22.61
	E2,C	1.50	7.55	13.60	25.70
Springfield, OR	E2,C	1.50	7.05	12.60	23.70
Steilacoom, WA	E2,C	3.50	9.75	16.00	28.50
Sumas, WA	E2	4.00	10.50	17.00	30.00
Tacoma, WA	E2,C	2.50	8.09	13.68	24.86
Vera Water & Power, WA	E2,C	2.25	6.60	10.95	19.65

[1]For customers outside city limits, add 90¢ to each bill.
[2]Inverted rate except for first block.
[3]Summer Rate April 1 - August 31.
[4]Winter Rate September 1 - March 31.
[5]Lifeline Rate.
[6]All Electric Rate.
[7]December through March: add 10 percent to bills.

TYPICAL MONTHLY ELECTRIC BILLS

Public Utility Districts	RATE TYPE	MINIMUM BILL	RESIDENTIAL SERVICE 500 kwh	1000 kwh	2000 kwh
Benton County PUD, WA	E2,C	3.50	9.55	15.60	27.70
Central Lincoln PUD, OR	E2,C	4.40	9.65	14.90	25.40
Chelan County PUD, WA[1]	E3,C	3.50	7.00	11.00	19.00
Clallam County PUD, WA	E1,C	3.50	10.80	17.30	30.30
Clark County PUD, WA	E4	3.00	6.60	11.10	22.40
Clatskanie County PUD, OR	E1	2.00	5.60	10.10	19.10
Cowlitz County PUD, WA	E2	3.00	4.38	8.75	17.50
Douglas County PUD, WA[1]	E2,C	4.00	11.00	17.00	30.00
Ferry County PUD, WA[1]	E2,C	6.00	13.50	21.00	36.00
Franklin County PUD, WA	E2,C	3.50	9.30	15.10	26.70
Grant County PUD, WA[1]	E1,C	4.00	10.00	15.00	25.00
Grays Habor County PUD, WA	E4	2.00	6.52	9.47	16.57
Kittitas County PUD, WA	E1,C	4.50	13.25	22.00	38.25
Klickitat County PUD, WA[1]	E1	4.00	10.00	17.00	30.00
Lewis County PUD, WA	E4	3.00	7.05	11.55	21.55
Mason County PUD No. 1, WA	E1	4.00	9.30	15.30	27.30
Mason County PUD No. 3, WA	E1	5.00	11.00	17.00	26.60
Northern Wasco County PUD, OR	E2,C	4.00	10.25	16.50	29.00
Okanogan County PUD, WA[1]	E1	4.00	8.00	12.00	21.00
Pacific County PUD, WA	E2,C	5.00	10.25	15.50	26.00
Pend Oreille County PUD, WA[3]	E1	5.00	10.71	16.56	28.26
Skamania County PUD, WA	E1	5.00	10.40	16.90	29.90
Snohomish County PUD, WA	E2,C	1.80	6.60	11.40	21.00
Tillamook PUD, OR[4]	E1[2]	8.00	9.00	14.00	25.00
	E1	3.00	9.00	15.00	26.00
Wahkiakum County PUD, WA	E2,C	7.00	13.50	20.00	33.00

[1]Distributor uses whole dollar billing; amounts shown are rounded to nearest dollar.
[2]All Electric Rate.
[3]Overhead Service.
[4]Residential billing to the nearest $0.50 through $8.00 and to nearest dollar over $8.00.

TYPICAL MONTHLY ELECTRIC BILLS

Cooperatives	RATE TYPE	MINIMUM BILL	500 kwh	1000 kwh	2000 kwh
			RESIDENTIAL SERVICE		
Alder Mutual Light Co., WA	E1	6.00	12.50	20.00	35.10
Benton REA, WA[1]	E1	4.00	10.00	14.00	23.00
Big Bend Elec. Coop. Inc., WA	E1	4.00	11.00	16.00	25.00
Blachly Lane Co. Coop. Elec. Assn., OR[1]	E2,C	3.50	11.00	18.00	32.00
B.I.A. Flathead Irrigation Project	E4	1.50[2]	7.00	12.00	27.00
Central Elec. Coop. Inc., OR	E1	6.25	16.25	24.75	39.25
Clearwater Power Co., ID	E1,C,D	4.00	15.35	22.60	37.10
Columbia Basin Elec. Coop. Inc., OR	E1,C,D	5.00	10.00	16.25	28.75
Columbia Power Coop. Assn., OR	E1,C	6.00	23.50	31.00	46.00
Columbia REA, WA	E1,C	5.00	12.00	17.50	28.50
Consumers Power, OR	E2,C	3.25	12.95	22.65	42.05
Coos-Curry Elec. Coop. Inc., OR	E1,C	4.00	12.25	20.50	37.00
Douglas Elec. Coop. Inc., OR	E1,C	3.00	13.00	23.00	35.50
East End Mutual Elec. Co., ID[3]	E1	3.60	10.88	16.68	28.28
Elmburst Mutual Power & Light Co., WA[1]	E1	2.50	8.00	14.00	25.00
Fall River Rural Elec. Coop. Inc., ID	E1,C	6.00	17.00	28.00	46.00
Farmers Elec. Co., Ltd., ID[3]	E1	4.00	4.25	7.08	12.08
Flathead Elec. Coop. Inc., MT[1]	E1,D	4.00	13.00	19.00	32.00
Glacier Elec. Coop. Inc., MT	E1	1.50	10.75	16.50	28.00
Harney Elec. Coop., OR[4,5]	E1	5.00	12.00	18.00	30.00
Hood River Elec. Coop., OR	E2,C	3.00	9.62	16.25	29.50
Idaho Co. Light & Power Co., ID	E2,C	5.00	14.65	24.30	43.60
Inland Power & Light Co., WA	E1	4.00	14.75	21.25	34.25
Kootenai REA, ID	E1	5.94	14.48	21.01	34.07
Lakeview Light & Power Co., WA[1]	E2,C	3.00	6.00	11.00	21.00
Lane Elec. Coop. Inc., OR	E2,C	4.00	9.35	14.70	25.40
Lincoln Elec. Coop. Inc., MT	E1	3.50	13.25	19.75	29.75
Lincoln Elec. Coop. Inc., WA[1]	E1	10.00	18.00	24.00	34.00
Lost River Elec. Coop. Inc., ID	E1	1.65[6]	10.90	18.90	31.90
Lower Valley Power & Light, ID	E1[7]	10.00	14.44	20.24	31.84
	E1	6.00	14.96	22.06	36.26
Midstate Elec. Coop. Inc., OR	E1	5.00	12.20	17.70	28.70
Missoula Elec. Coop. Inc., MT	E1,C	5.00	15.34	24.69	43.39
Nespelem Valley Elec. Coop. Inc., WA	E1	4.00	9.00	14.00	23.00
Northern Lights Inc., ID[1]	E1	6.00	15.00	23.00	38.00
Ohop Mutual Light Co., WA	E2,C	8.00	15.50	23.00	38.00
Okanogan Co. Elec. Coop. Inc., WA[1]	E1,C	3.60	9.00	15.00	26.00
Orcas Power & Light Co., WA	E1,C	6.00	22.12	29.12	43.12

[1]Distributor uses whole dollar billing; amounts shown are rounded to nearest dollar.
[2]Rural minimum $3.00.
[3]Quarterly billing.
[4]Nonfarm rural and farm minimum $15.00.
[5]Bill is net the 20 percent prompt payment discount.
[6]Rural minimum $3.30.
[7]All Electric Rate.

TYPICAL MONTHLY ELECTRIC BILLS

RESIDENTIAL SERVICE

Cooperatives (cont.)	RATE TYPE	MINIMUM BILL	500 kwh	1000 kwh	2000 kwh
Peninsula Light Co., Inc.	E4	5.15	12.10	18.85	32.35
Parkland Light & Water Co., WA[1]	E1	3.00	8.00	12.00	22.00
Prairie Power Coop. Inc., ID (Urban)	E1	8.00	23.50	32.40	44.40
(Rural)	E1	16.00	23.50	32.40	44.40
Raft River Rural Elec. Coop., ID	E2,C	5.75	10.75	15.75	25.75
Ravalli Elec. Coop. Inc., MT	E1	5.00	14.27	22.77	39.77
Riverside Elec. Co. Ltd., ID	E1	3.25	6.60	11.60	21.60
Rural Elec. Co., ID	E1	2.50	8.75	13.75	23.75
Salem Electric, OR	E1	4.20	8.19	14.84	28.14
Salmon River Elec. Coop., ID	E1	2.00	19.40	27.60	46.30
South Side Elec. Lines Inc., ID	E1	3.00	10.80	15.30	24.30
Surprise Valley Elec. Corp. CA	E1	6.00	12.50	20.00	32.60
Tanner Electric, WA	E2,C	9.00	19.00	29.00	49.00
Umatilla Elec. Coop. Assn., OR	E1,C	4.00	10.70	16.20	27.20
Unity Light & Power Co., ID	E4	3.00	8.00	13.00	23.20
Vigilante Elec. Coop. Assn., MT	E1	4.00	14.20	23.45	39.70
Wasco Elec. Coop. Inc., OR	E2,C	5.00	12.50	20.00	35.00
Wells Rural Elec. Co., NV					
Nevada-Farm & Home	E1	4.50	25.50	36.00	57.00
Nevada-Village	E1	1.35	18.33	28.83	49.83
Utah-Farm & Home	E1	4.50	23.11	31.21	47.42
Utah-Village	E1	1.35	15.93	24.04	40.25
West Oregon Elec. Coop. Inc., OR	E2,C	9.00	18.25	27.50	46.00

[1]Distributor uses whole dollar billing; amounts shown are rounded to nearest dollar.

TYPICAL MONTHLY ELECTRIC BILLS

RESIDENTIAL SERVICE

Private Utilities	RATE TYPE	MINIMUM BILL	500 kwh	1000 kwh	2000 kwh
C P National, OR	E1	1.82	17.52	26.06	46.29
Citizens Utilities Company, ID	E1,D	1.85	10.55	18.05	33.05
Idaho Power Company:					
Idaho	E1,C	4.00	14.49	24.97	45.94
Oregon	E1,C	4.00	14.49	24.97	45.94
Montana Power Company, MT	E1	1.69	15.39	24.79	43.59
Pacific Power & Light Company:					
Oregon:					
Summer	E2,C[7]	3.00	15.13	27.25	51.50
Winter	E2,C[7]	3.00	16.35	29.69	56.38
Idaho	E2,C	2.00	11.85	20.37	38.74
Montana	E2,C	2.00	11.56	21.11	40.22
Washington	E2,C	3.00	12.48	21.95	40.90
Portland General Elec. Company, OR	E2,C[3]	3.00	14.75	26.49	49.98
	E2,C[2]	3.00	15.92	28.84	54.68
Puget Sound Power & Light Co., WA[1]	E3,C[6]	3.45	12.28	21.11	39.72
Utah Power & Light Company, ID	E2,C[3]	4.56	23.22	41.89	79.21
	E2,C[2]	4.56	18.82	33.09	61.61
Washington Water Power Company:					
Washington	E3,C[5]	2.80	9.73	16.66	32.03
Idaho	E2,C[4]	2.60	9.34	16.07	29.54

[1]All territories except Pt. Roberts.
[2]Charges from November through April.
[3]Charges from May through October.
[4]Surcharge: add 0.010¢ per kWh for all energy used.
[5]Surcharge: add 0.013¢ per kWh for all energy used.
[6]Energy Rate Adjustment: add -.0144¢ per kWh.
[7]Add: $3.00 per bill for 3-phase service.

TYPICAL MONTHLY ELECTRIC BILLS

COMMERCIAL SERVICE

Municipalities	RATE TYPE	6 KW 750 kwh	12 KW 1500 kwh	30 KW 6000 kwh	75 KW 15,000 kwh	75 KW 30,000 kwh	150 KW 30,000 kwh	150 KW 60,000 kwh
Albion, ID	E1	13.25	21.20	75.20	194	336	393	678
Ashland, OR	E1,D	24.34	41.86	135.01	337	526	625	967
Bandon, OR	E1,D	13.75	22.25	65.00	181	256	346	496
Blaine, WA[1]	E2,C	14.25	25.50	93.00	231	456	456[2]	796[2]
Bonners Ferry, ID[3]	E1,C,D	19.68	31.05	108.25	282	447	556	886
Burley, ID	E1,D	18.00	31.50	88.20	229	350	431	674
Canby, OR[4]	E1,C,D	19.50	37.50	139.50	320	475	587	767
Cascade Locks, OR (Local)	E1,D	28.75	48.76	125.35	291	394	498	705
(Rural)	E1,D	31.63	53.36	135.13	311	425	528	756
Centralia, WA	E1,C	18.75	30.00	93.00	188	345	345	660
Cheney, WA[5]	E1,D	23.25	33.00	89.50	227	362	479	728
Coulee Dam, WA	E1,D	17.55	27.30	72.30	162	255	255	441
Declo, ID	E1	14.56	22.32	68.90	162	317	317	628
Drain, OR	E1,C,D	18.75	32.30	107.00	269	350	457	619
Eatonville, WA	E1	16.06	25.96	85.36	204	402	402	798
Ellensburg, WA	E1[6]	13.50	22.50	73.50[9]	249[9]	339[9]	497[9]	677[9]
	E1[7]	14.23	23.82	77.97[9]	260[9]	364[9]	522[9]	731[9]
Eugene, OR[8]	E1,C,D	23.78	42.32	116.09	282	370	559	735
Fircrest, WA	E1	13.80	21.60	64.80	151	295	295	583
Forest Grove, OR	E1,C,D	15.13	26.00	83.15	232	370	473	703
Heyburn, ID	E1,D	13.45	24.10	90.70	235	370	460	730
Idaho Falls, ID	E1[11]	19.07	28.29	83.64	194	379	379	748
	E1,D	25.50	48.40	142.00	345	457	585	810
McCleary, WA	E1	18.00	30.00	68.50	132	237	237	447
McMinnville, OR	E1,C,D	17.00	29.00	101.00	283	448	560	800
Milton, WA	E2,C	16.63	28.25	98.00	238	470	470	935
Milton-Freewater, OR	E1	8.46	14.76	52.56	166[9]	248[9]	343[9]	508[9]
Minidoka, ID	E1	14.85	23.85	64.35	145	280	280	550
Monmouth, OR	E1	10.74	19.66	73.21	302[9]	407[9]	539[9]	749[9]
Port Angeles, WA	E1	11.25	18.00	56.70	167	239	333	477
Richland, WA	E2,C	17.05	27.10	87.40	240[12]	300[12]	472[12]	592[12]
Rupert, ID	E1,D	22.35	42.50	110.00	259	364	494	682
Seattle, WA[10]	E1,C,D	14.25	25.50	93.00	222	304[9]	394[9]	559[9]
Springfield, OR	E1	10.35	20.70	82.80	182	285	365	570
Steilacoom, WA	E2,C	12.88	22.25	78.50	191	379	379	754
Sumas, WA	E1	22.00	38.50	125.50	252	402	402	702
Tacoma, WA	E2,C	14.15	25.55	93.95	225[11]	324[11]	418[11]	616[11]
Vera Water & Power, WA	E1,C	15.50	26.00	66.50	178	283	380	590

[1]Assumptions: $3.00 customer charge through 75 kW and $6.00 for 150 kW.
[2]Rate Type E2,C,D.
[3]For customers outside city limits, add 90¢ to each bill.
[4]Assumptions: Single Phase service through 150 kW.
[5]Inverted rate except for first block.
[6]Summer Rate April 1 - August 31.
[7]Winter Rate September 1 - March 31.
[8]For three phase service, add $1.55 per month.
[9]Rate Type E1,D.
[10]December through March: add 10 percent to bills.
[11]Rate Type E1,D., All Electric Rate.
[12]Rate Type E1,C.

TYPICAL MONTHLY ELECTRIC BILLS

COMMERCIAL SERVICE

Public Utility Districts	RATE TYPE	6 KW 750 kwh	12 KW 1500 kwh	30 KW 6000 kwh	75 KW 15,000 kwh	75 KW 30,000 kwh	150 KW 30,000 kwh	150 KW 60,000 kwh
Benton Co. PUD, WA	E1,C,D	14.53	24.05	81.20	250	373	500	714
Central Lincoln PUD, OR	E2,C,D	12.28	20.15	67.40	194	299	381	591
Chelan Co. PUD, WA[1]	E1,C,D	19.00	28.00	80.00	217	330	442	667
Clallam Co. PUD, WA	E1,D	17.00	30.75	95.25	247	442	468	858
Clark Co. PUD, WA	E1,D	14.80	23.80	77.88	247	361	462	638
Clatskanie PUD, OR	E1,D	9.38	17.50	74.50	205	300	405	565
Cowlitz Co. PUD, WA	E1	13.31	22.31	69.31	152	255[3]	290[3]	443[3]
Douglas Co. PUD, WA[1]	E2,C,D	14.00	24.00	82.00	199	394	394	784
Ferry Co. PUD, WA[1]	E1,C[4]	24.75	43.50	111.00	246	471	608	878
Franklin Co. PUD, WA	E1,C,D	15.00	24.00	78.00	247	375	506	761
Grant Co. PUD, WA[1]	E1,C	17.00	28.00	89.00	193	343	343	643
Grays Harbor Co. PUD, WA	E1	12.48	21.46	74.95	182	313	355	501[5]
Kittitas Co. PUD, WA	E1,C,D	22.50	40.50	99.00	216	351	491	701
Klickitat Co. PUD, WA[1]	E1,D	18.00	30.00	87.00	236	367	468	729
Lewis Co. PUD, WA	E1,D	17.00	32.00	77.00	198	303	397	607
Mason Co. PUD No. 1, WA	E1	16.40	26.90	106.00	214	394	394	754
Mason Co. PUD No. 3, WA	E1,D	20.50	32.25	87.75	209	299	393	543
Northern Wasco Co. PUD, OR	E1,C	29.50	44.50	112.00	304[5]	454[5]	570[5]	870[5]
Okanogan Co. PUD, WA[1]	E1,D	15.00	26.00	100.00	258	378	453	693
Pacific Co. PUD, WA	E1,C,D	18.88	30.50	112.00	256	384	496	681
Pend Oreille Co. PUD, WA	E1	20.20	29.80	84.70	195	378	378	744
Skamania Co. PUD, WA	E1,D	21.18	38.88	146.28	320	441	554	797
Snohomish Co. PUD, WA	E1,C[2]	15.30	27.00	86.40	178	331	331	637
	E1,C	15.30	27.00	90.00	198	378	378	738
Tillamook PUD, OR	E1[2]	16.00	25.00	79.00	187	367	367	727
	E1,D	22.45	37.45	94.95	241	335	429	616
Wahkiakum Co. PUD, WA	E1,D	32.55	42.30	114.80	295	464	569	839

[1]Distributor uses whole dollar billing; amounts shown are rounded to nearest dollar.
[2]All Electric Rate.
[3]Overhead Service.
[4]Single-Phase Service through 1500 kWh.
[5]Rate Type E2,D.

TYPICAL MONTHLY ELECTRIC BILLS

COMMERCIAL SERVICE

Cooperatives	RATE TYPE	6 KW	12 KW	30 KW	75 KW		150 KW	
		750 kwh	1500 kwh	6000 kwh	15,000 kwh	30,000 kwh	30,000 kwh	60,000 kwh
Alder Mutual Light Co., WA	E1	18.75	30.00	97.50	233	458	458	908
Benton REA, WA[1]	E1,D	15.00	22.00	77.00	227	287	437	557
Big Bend Elec. Coop. Inc., WA[1]	E1,D	14.00	22.00	77.00	232	307	457	607
Blachly Lane Co. Coop. Elec. Assn., OR	E2,C	14.00	25.00	88.00	263[5]	375[5]	495[5]	720[5]
B.I.A. Flathead Irrigation Project	E1	16.00	31.00	108.00	240	360	432	648
Central Elec. Coop. Inc., OR	E1,D	26.75	41.20	122.50	276	411	531	764
Clearwater Power Co., ID	E1,C,D	18.98	29.85	91.10	242	347	512	722
Columbia Basin Elec. Coop. Inc., OR	E1,D	22.00	37.00	108.00	279	434	539	749
Columbia Power Coop. Assn., OR	E1,C	34.25	45.50	113.00	248	473	473	923
Columbia REA, WA	E1,C,D	20.25	28.50	78.00	245	385	497	677
Consumers Power, OR	E1,C,D	17.80	32.35	148.95	362	576	708	1117
Coos-Curry Elec. Coop. Inc., OR	E1,C	22.00	40.00	112.00	282[4]	477[4]	586[4]	856[4]
Douglas Elec. Coop. Inc., OR	E1,D	21.75	40.50	96.75	236	386	483	783
East End Mutual Elec. Co., ID	E1	13.78	22.48	74.68	179	353	353	701
Elmhurst Mutual Light & Power Co., WA[1]	E1	15.00	25.00	83.00	311	446	547	817
Fall River Rural Elec. Coop. Inc., ID	E1,C,D	35.00	66.20	182.75	416	641	799	1221
Farmers Elec. Co. Ltd., ID[2]	E1	5.83	9.59	32.08	77	152	152	302
Flathead Elec Coop. Inc., MT[1]	E1,D	16.00	26.00	84.00	251	446	596	986
Glacier Elec. Coop. Inc., MT	E1,D	24.40	38.40	110.90	265	424	510	757
Harney Elec. Coop., OR[3]	E1	15.00	24.00	78.00	190	370	370	730
Hood River Elec. Coop., OR	E2,C	12.94	22.88	82.50	248[4]	368[4]	480[4]	720[4]
Idaho Co. Light & Power Co., ID	E2,C,D	19.48	33.95	120.80	315	525	630	1050
Inland Power & Light Co., WA	E1,D	26.30	45.05	110.80	293	443	552	832
Kootenai REA, ID	E1,D	21.07	32.06	90.83	229	354	487	736
Lakeview Light & Power Co., WA[1]	E2,C	9.00	16.00	61.00	155	305	305	605
Lane Elec. Coop. Inc., OR	E2,C	12.03	20.05	66.00[4]	175[4]	280[4]	370[4]	580[4]
Lincoln Elec. Coop. Inc., MT	E1	17.25	24.75	69.75	248[4]	398[4]	495[4]	735[4]
Lincoln Elec. Coop. Inc., WA[1]	E1	21.00	29.00	75.00	168[4]	322[4]	322[4]	631[4]
Lost River Elec. Coop. Inc., ID	E1,D	14.90	25.40	92.90	291	421	621	842
Lower Valley Power & Light, ID	E1,D	21.81	38.83	106.98	181	376	534	830
Midstate Elec. Coop. Inc., OR	E1,D	21.75	33.00	73.50	218	308	405	585
Missoula Elec. Coop. Inc., MT	E1,D	22.88	36.90	121.05	339	496	645	942
Nespelem Valley Elec. Coop. Inc., WA[1]	E1	11.00	18.00	59.00	218[4]	323[4]	428[4]	638[4]
Northern Lights Inc., ID[1]	E1	38.00	61.00	136.00	280	520	930[4]	1350[4]

[1]Distributor uses whole dollar billing; amounts shown are rounded to nearest dollar.
[2]Quarterly billing.
[3]Bill is net the 20 percent prompt payment discount.
[4]Rate Type E1,D.
[5]Rate Type E1,C,D.

TYPICAL MONTHLY ELECTRIC BILLS

COMMERCIAL SERVICE

Cooperatives (cont.)	RATE TYPE	6 KW	12 KW	30 KW	75 KW		150 KW	
		750 kwh	1500 kwh	6000 kwh	15,000 kwh	30,000 kwh	30,000 kwh	60,000 kwh
Ohop Mutual Light Co., WA	E2,C	19.25	30.50	98.00	233	458	458	908
Okanogan Co. Elec. Coop. Inc., WA[1]	E1,C	12.00	20.00	70.00	169	304	304	544
Orcas Power & Light Co., WA	E1,C,D	25.62	36.12	99.75	224	393	431	770
Peninsula Light Co., Inc.	E4	17.68	30.80	109.55	267	530	530	1055
Parkland Light & Water Co., WA[1]	E1	10.00	14.00[3]	57.00[3]	143[3]	285[3]	285[3]	570[3]
Prairie Power Coop. Inc., ID	E1	34.15	58.90	190.90	276	381	528	738
Raft River Rural Elec. Coop., ID	E2,C	13.25	20.75	67.50	273[4]	285[4]	535[4]	760[4]
Ravalli Elec. Coop. Inc., MT	E1,D	18.52	31.27	107.77	296	461	566	896
Riverside Elec. Co. Ltd., ID	E1	9.10	16.60	61.60	152	302	302	602
Rural Elec. Co., ID	E1,D	20.10	38.20	103.00	243	343	455	635
Salem Electric, OR	E1,D	17.50	28.00	91.00[4]	259[4]	364[4]	490[4]	700[4]
Salmon River Elec. Coop., ID	E2,D	25.05	37.80	114.30	390	600	780	1200
South Side Elec. Lines Inc., ID	E1	13.05	19.80	60.30	141	276	276	546
Surprise Valley Elec. Corp., CA	E1	22.75	41.50	95.50	293[2]	398[2]	585[2]	795[2]
Tanner Electric, WA[5]	E1,C,D	31.50	54.00	173.00	461	761	911	1511
Umatilla Elec. Coop. Assn., OR	E1,D	12.75	25.50	86.50	249	324	444	594
Unity Light & Power Co., ID	E1,D	10.50	18.00	91.50	229	334	458	668
Vigilante Elec. Coop. Assn., MT	E1	28.10	45.60	110.60	328[2]	448[2]	626[2]	866[2]
Wasco Elec. Coop. Inc., OR	E1,C,D	26.25	37.50	127.50	330	555	675[2]	980[2]
Wells Rural Elec. Co., NV:								
Nevada	E1	50.00	92.00	255.50	521[2]	761[2]	1043[2]	1523[2]
Utah	E1	46.41	84.82	226.76	449	618	899	1235
West Oregon Elec. Coop. Inc., OR	E2,C	22.88	36.75	120.00	287	564	564	1119

[1]Distributor uses whole dollar billing; amounts shown are rounded to nearest dollar.
[2]Rate Type E1,D.
[3]Rate Type E2.
[4]Rate Type E2,D.
[5]For three phase service, add $18.00 to each bill.

TYPICAL MONTHLY ELECTRIC BILLS

COMMERCIAL SERVICE

Private Utilities	RATE TYPE	6 KW 750 kwh	12 KW 1500 kwh	30 KW 6000 kwh	75 KW 15,000 kwh	75 KW 30,000 kwh	150 KW 30,000 kwh	150 KW 60,000 kwh
C P National, OR	E1	33.94	60.69	196.62	444	751	858	1399
Citizens Utilities Company, ID	E1,D	25.85	40.85	130.85	311	611	611	1211
Idaho Power Company:								
Idaho	E1,D	36.34	69.72	193.24	461	696	907	1298
Oregon	E1,D	36.34	69.72	192.24	461	696	907	1298
Montana Power Company, MT	E1,D	35.63	73.05	216.59	411	605	706	1029
Pacific Power & Light Company:								
Oregon:								
Summer	E1,C,D[5]	25.30	45.59	156.05	366	614	711	1207
Winter	E1,C,D[5]	27.33	49.66	169.43	395	643	766	1262
Idaho	E1,C	28.21	44.91	143.00	348	560	656	988
Montana	E2,C	23.20	44.41	174.62	352	554	611	1015
Washington	E1,D	31.00	52.97	168.94	405	654	753	1206
Portland General Electric Company, OR:								
Summer	E2,C	23.32	41.64	148.59	419	672	822	1326
Winter	E2,C	25.15	45.30	162.93	483	736	938	1443
Puget Sound Power & Light Co., WA[1,2]	E1,C,D	24.45	45.44	171.43	423	722	874	1471
Utah Power & Light Company, ID	E1,C,D[3]	59.22	127.84	411.10	760	1021	1377	1901
	E1,C,D[4]	54.50	111.20	349.43	670	932	1199	1722
Washington Water Power Company:								
Washington	E1,C,D	19.43	36.06	157.82	358	575	667	1103
Idaho	E1,C,D	19.06	35.52	141.10	325	520	607	989

[1]Energy Rate Adjustment: add -.0144¢ to all energy.
[2]For three-phase service add: $9.55 to each bill.
[3]Summer Rate: May through October.
[4]Winter Rate: November through April.

TYPICAL MONTHLY ELECTRIC BILLS

INDUSTRIAL POWER

Municipalities	RATE TYPE	500 KW		1000 KW	5000 KW
		100,000 kwh	200,000 kwh	400,000 kwh	2,500,000 kwh
Albion, ID	E1	1321	2271	4546	27496
Ashland, OR	E1,D	1918	3057	5922	34137
Bandon, OR	E1,D	1121	1596	3021	15561
Blaine, WA	E2,C,D	1506	2406	4806	--
Bonners Ferry, ID[1]	E1,C,D	1680	2340	4385	24045
Burley, ID	E1,D	1345	2065	4045	23485
	E1,D	1345	2065	4045	23485
Canby, OR[2]	E1,C,D	1535	2135	4085	22685
Cascade Locks, OR (Local)	E1,D	1314	1751	3281	17702
(Rural)	E1,D	1382	1862	3479	18818
Centralia, WA	E1,C,D	1200	1700	3300	18600
Cheney, WA	E4,D	1371	1821	3396	18246
Coulee Dam, WA	E1,D	1021	1610	3311	19859
Declo, ID	E1	1042	2077	4147	--
Drain, OR	E1,C,D	1332	1872	3662	20482
Eatonville, WA	--	--	--	--	--
Ellensburg, WA	E1,D[3]	1568	1928	3032	18992
	E1,D[4]	1661	2118	4082	22079
Eugene, OR	E1,C,D	1597	2120	4163	23122
Fircrest, WA	E1	967	1927	3847	24007
Forest Grove, OR	E1,C,D	1462	1882	3412	17752
Heyburn, ID	E1,D[4]	1650	2150	4300	23750
	E1,D[3]	1300	1575	3150	17000
Idaho Falls, ID	E1,D	1704	2364	4584	24444
McCleary, WA	E1,D	995	1328	2468	13250
McMinnville, OR	E1,C,D	1585	2035	3685	19135
Milton, WA	--	--	--	--	--
Milton-Freewater, OR	E1,D	1106	1486	2871	15851
Minidoka, ID	--	--	--	--	--
Monmouth, OR	E1,D	1492	1967	3749	20374
Port Angeles, WA	E1	999	1269	2538	13770
Richland, WA	E1,C	1557	1957	3907	21507
Rupert, ID	E1,D	1565	2141	--	--
Seattle, WA[5,6]	E1,D	1150	1540	3005	15025
Springfield, OR	E1	1154	1625	3121	16694
Steilacoom, WA	E2,C	1254	2504	5004	--
Sumas, WA	E1	1102	2102	4102	25102
Tacoma, WA	E1,D	1317	1817	3442	17942
Vera Water & Power, WA	E1,C,D	1220	1620	3070	16670

[1] Customers outside city limits, add 90¢ to each bill.
[2] Assumption: Three-Phase Service.
[3] Summer Rate April 1 - August 31.
[4] Winter Rate September 1 - March 31.
[5] No "Seasonal Factor" included in computation.
[6] December through March: add 10 percent to bills.

TYPICAL MONTHLY ELECTRIC BILLS

INDUSTRIAL POWER

Public Utility Districts	RATE TYPE	500 KW		1000 KW	5000 KW
		100,000 kwh	200,000 kwh	400,000 kwh	2,500,000 kwh
Benton Co. PUD, WA	E1,C,D	1459	1914	3534	18544
Central Lincoln PUD, OR	E1,D	1305	1555	2860	14300
Chelan Co. PUD, WA[1]	E1,D	1250	1900	3400	17650
Clallam Co. PUD, WA	E1,D	1453	2103	4153	23803
Clark Co. PUD, WA	E1,D	1176	1586	3173	17763
Clatskanie PUD, OR	E1,D	1255	1755	3455	19555
Cowlitz Co. PUD, WA	E2,D	934	1475	2950	17250[2]
Douglas Co. PUD, WA[1]	E2,C	1304	2604	5204	32504
Ferry Co. PUD, WA[1]	E2,C,D	1900	2800	5600	32550
Franklin Co. PUD, WA	E1,C,D	1466	1966	3716	20216
Grant Co. PUD, WA[1]	E1,D	1396	1813	3305	17166
Grays Habor Co. PUD, WA	E1,D	1165	1525	3050	16450
Kittitas Co. PUD, WA	E1,C,D	1471	1931	3431	17431
Klickitat Co. PUD, WA[1]	E1,D	1332	1759	3257	17363
Lewis Co. PUD, WA	E1,D	1225	1625	3250	18250
Mason Co. PUD No. 1, WA	E1	--	--	--	--
Mason Co. PUD No. 3, WA	E1,D	1180	1680	2033	10878
Northern Wasco Co. PUD, OR	E1,D	1673	2273	4248	23048
Okanogan Co. PUD, WA[1]	E1,D	1205	1555	2948	15098
Pacific Co. PUD, WA	E1,C,D	1406	1906	3656	[3]
Pend Oreille Co. PUD, WA	E1,D	1433	2051	3899	21533
Skamania Co. PUD, WA	E1,D	1571	2081	3851	20561
Snohomish Co. PUD, WA	E2,D[4]	800	1100	2200	10250
	E2,D[5]	1075	1575	3150	13875
Tillamook PUD, OR	E1,D	1177	1595	3025	16553
Wahkiakum Co. PUD, WA	E1,D	1689	2589	5089	29589

[1]Distributor uses whole dollar billing; amounts shown are rounded to nearest dollar.
[2]Winter Billing (September-March) shown. Summer Billing (April-August) $14,000.
[3]Special Contract.
[4]Summer Rate April - August.
[5]Winter Rate September - March.

TYPICAL MONTHLY ELECTRIC BILLS

INDUSTRIAL POWER

Cooperatives	RATE TYPE	500 KW 100,000 kwh	500 KW 200,000 kwh	1000 KW 400,000 kwh	5000 KW 2,500,000 kwh
Alder Mutual Light Co., WA	--	--	--	--	--
Benton REA, WA	E1,D[1]	1417	1817	2818	13313
	E1,D[2]	1417	1817	3350	15800
Big Bend Elec. Coop. Inc., WA[3]	E1,D	1356	1806	3606	20256
Blachly Lane Co. Coop. Elec. Assn., OR	E1,C,D	1580	2330	4230	22180
B.I.A. Flathead Irrigation Project	E1	1178	1767	2903	17710
Central Elec. Coop. Inc., OR	E1,D	1604	2304	4504	25604
Clearwater Power Co., ID	E1,C,D	1562	2062	3862	20762
Columbia Basin Elec. Coop. Inc., OR	E1,D	1259	1667	3086	16138
Columbia Power Coop. Assn., OR	E1,C	1523	3023	6023	--
Columbia REA, WA	E1,C,D	1341	1899	3713	21011
Consumers Power, OR	E1,C,D	2250	3400	6275	29025
Coos-Curry Elec. Coop. Inc., OR	E1,D	1485	1960	3599	19084
Douglas Elec. Coop. Inc., OR	E1,D	1750	2650	5100	29200
East End Mutual Elec. Co., ID	--	--	--	--	--
Fall River Rural Elec. Coop. Inc., ID	E1,C,D	2516	3916	--	--
Farmers Elec. Co. Ltd., ID	--	--	--	--	--
Flathead Elec. Coop. Inc., MT[3]	E1,D	2206	3506	7106	--
Glacier Elec. Coop. Inc., MT	E1,D	1439	3139	4114	23414
Harney Elec. Coop., OR[4]	E1,D	1816	3016	6016	--
Hood River Elec. Coop., OR	E1,D	1565	2165	4115	22715
Idaho Co. Light & Power Co., ID	E2,D	2050	3450	6900	--
Inland Power & Light Co., WA	E1,D	1659	2359	4484	24984
Kootenai REA, ID	E1,D	1602	2349	4733	27540
Lakeview Light & Power Co., WA[3]	--	--	--	--	--
Lane Elec. Coop. Inc., OR	E1,D	1180	1630	3130	17380
Lincoln Elec. Coop. Inc., MT	E1,D	1470	2170	4220	24120
Lincoln Elec. Coop. Inc., WA[3]	E1,D	1683	2615	4568	19769
Lost River Elec. Coop. Inc., ID	E1,D	1930	2609	5217	27714
Lower Valley Power & Light, ID	E1,D	1904	2744	5479	31560
Midstate Elec. Coop. Inc., OR	E1,D	1199	1722	3384	16660
Missoula Elec. Coop. Inc., MT	E1,D	2031	3021	5991	34701
Nespelem Valley Elec. Coop. Inc., WA[3]	E1,D	1408	2108	4208	24508
Northern Lights Inc., ID[3,5]	E1,D	2575	3525	6075	--

[1]Summer Rate approximately March 20 - August 20.
[2]Winter Rate approximately August 20 - March 20.
[3]Distributor uses whole dollar billing; amounts shown are rounded to nearest dollar.
[4]Bill is net the 20 percent prompt payment discount.
[5]Primary voltage available on request.

TYPICAL MONTHLY ELECTRIC BILLS

INDUSTRIAL POWER

Cooperatives (cont.)	RATE TYPE	500 KW 100,000 kwh	500 KW 200,000 kwh	1000 KW 400,000 kwh	5000 KW 2,500,000 kwh
Ohop Mutual Light Co., WA	E2,C	--	--	--	--
Okanogan Co. Elec. Coop. Inc., WA[1]	E1,C	777	1497	2937	18057
Orcas Power & Light Co., WA	E1,C,D	1397	2527	5037	--
Parkland Light & Water Co., WA[1]	E2	950	1900	3800	23750
Prairie Power Coop. Inc., ID	E1,D	1581	2232	4441	25366
Riverside Elec. Co. Ltd., ID	--	--	--	--	--
Rural Elec. Co., ID	E1,D	1400	1970	3870	21070
Raft River Rural Elec. Coop., ID	E2,C,D	1675	2410	4810	27685
Ravalli Elec. Coop. Inc., MT	E1,D	1826	2926	5826	34526
Salem Electric, OR	E1,D	1490	1822	3285	16652
Salmon River Elec. Coop., ID	E2,D	2418	3720	7440	--
South Side Elec. Lines Inc., ID	--	--	--	--	--
Surprise Valley Elec. Corp., CA	E1,D	1755	2385	4770	27000
Tanner Electric, WA[3]	E1,C,D	3011	5011	10011	--
Umatilla Elec. Coop. Assn., OR	E1,D	1319	1719	3319	18119
Unity Light & Power Co., ID	--	--	--	--	--
Vigilante Elec. Coop. Assn., MT	E1,D	2018	2818	5605	--
Wasco Elec. Coop. Inc., OR	E1,D	1825	2625	4975	27775
Wells Rural Elec. Co., NV:					
Nevada	E1,D	3475	5075	2	2
Utah	E1,D	2996	4117	2	2
West Oregon Elec. Coop. Inc., OR	E2,C	2259	3509	7009	--

[1]Distributor uses whole dollar billing; amounts shown are rounded to nearest dollar.
[2]Special Contract.
[3]For Three-Phase Service, add $18.00 to each bill.

TYPICAL MONTHLY ELECTRIC BILLS

INDUSTRIAL POWER

Private Utilities	RATE TYPE	500 KW 100,000 kwh	500 KW 200,000 kwh	1000 KW 400,000 kwh	5000 KW 2,500,000 kwh
C P National, OR	E1	2575	3539	6808	29110
Citizens Utilities Company, ID	E1	2423	4223	8445	--
Idaho Power Company:					
Idaho	E1,D	2452	3592	5384	30070
Oregon	E1,D	2510	3170	5958	30978
Montana Power Company, MT	E1,D	2022	2912	5602	31172
Pacific Power & Light Company:					
Oregon:					
Summer	E1,C,D[5]	2296	3950	7822	46545
Winter	E1,C,D[5]	2474	4128	8522	49745
Idaho	E1,D	1958	3032	5762	32552
Montana	E2,D	1955	3300	6565	39410
Washington	E1,D	2299	3589	6859	38209
Portland General Electric Company, OR:					
Summer	E2,D	2537	4174	8408	47625
Winter	E2,D	2887	4524	9148	51325
Puget Sound Power & Light Company, WA	E1,C,D	2290[1]	3435[1]	6749[1]	30450[1,2]
Utah Power & Light Company, ID	E2,C,D[3]	3793	5402	10631	60508
	E2,C,D[4]	3288	4897	9621	55458
Washington Water Power Company:					
Washington	E1,D	1880	2877	5446	25530
Idaho	E1,D	1682	2533	4760	20830

[1]Energy Rate Adjustment: add -.0144¢ per kWh.
[2]Reactive power charge not included: .025¢ per KVaRH.
[3]Summer Rate: May through October.
[4]Winter Rate: November through April.

Appendix D

Comments Received on the Draft Environmental Impact Statement and Bonneville's Responses to Those Comments

The following comments represent excerpts from or summaries of comments received on Bonneville's Draft Environmental Impact Statement: Bonneville Power Administration Proposed 1979 Wholesale Rate Increase. The comments and responses to them have been grouped by topic area. The topic areas and their location within the appendix are as indicated below.

Assumptions

Comment: "While the EIS briefly sets forth the factors causing the rate increase, it does not provide specific justification or rationale for the increases. That is, the EIS accepts as given that the purchase of new power in general, and "net-billed" power in particular is quite expensive. The WEC believes that the EIS should more explicitly quantify what portion of the rate increase stems from such factors as cost overruns, general inflation and other significant causes behind the need for increased revenues. We also feel that some explanation should be offered as to why cost overruns occurred. Absent the disclosure of this information the region's ratepayers have no basis for determining whether such additional costs are justifiable -- or due simply to sloppy management, poor engineering and inferior workmanship."

Washington Environmental Council
Seattle, Washington

Response: An attempt has been made in Chapters II and III of the Final EIS to clearly identify the factors affecting Bonneville's revenue requirement. Figure III-1 on page III-13, which did not appear in the

Draft EIS, has been included to provide a clear picture of the relationship which is expected to exist between various cost components through the year 2035. Detailed information on costs associated with thermal resources from which Bonneville will be acquiring power under net-billing agreements is presented in a report by Theodore Barry and Associates (1979), entitled "Management Study of the Roles and Relationship of Bonneville Power Administration and the Washington Public Power Supply System." A copy of the report is available at a cost of $10.00 through BPA Information Officer, Mr. Gene Tollefson.

Comment: "This EIS assumes that both conservation and renewable energy resources will be utilized at levels which are cost-effective for individual customers. Yet, recently some of the region's private utilities have initiated residential insulation programs on the basis that they were cost-effective to the utility. The WEC believes that if BPA were to approach conservation and renewable resource utilization based on a similar test of cost-effectiveness, substantially different forecasts of use would result."

Washington Environmental Council
Seattle, Washington

Response: Regional energy legislation currently under consideration by Congress would make conservation and renewable resource development priorities for BPA. Reliable estimates of the effects which the implementation of such programs would have on current load forecasts are not presently available.

Comment: "Whenever marginal cost is discussed in this EIS it is assumed that this is the cost of new central station facilities. Numerous studies (and policy statements) have indicated that the most cost-effective new resource is energy saved through conservation. If BPA assumed that its marginal cost for new resources was the cost of the direct purchase of conservation (estimated at one-fifth to one-tenth the cost of new central station generation) then its analysis of the impact of electing to use marginal cost pricing would be substantially altered."

Washington Environmental Council
Seattle, Washington

Response: The power marketing statutes pursuant to which the Bonneville Power Administration markets power contain no express authority to purchase conservation. While implied authority is found, it has been concluded by the BPA General Counsel's office that it is limited to the purchase of energy that can demonstrably be shown to maximize the economical and efficient use of the hydro projects from which BPA markets power. Bonneville currently proposes to undertake several conservation pilot projects, including a residential home weatherization program, which are intended to determine whether regional conservation programs can meet this "maximization" test. If these programs demonstrate that conservation is cost effective and can be used to maximize the hydro resource, express Congressional approval for Regional efforts will be sought. Should BPA receive such authority there could be an effect on Bonneville's marginal costs.

Comment: "The assertion that the use of solar energy in the region will be insignificant assumes that the systems must be cost-effective to the individual before they will be used. An alternative assumption is that they will be purchased and installed by utilities when they become the utilities "least cost" option for meeting a specific consumer end use need. Since this is presently occurring with residential insulation this assumption appears reasonable and should be used to forecast solar's impact on regional electrical demand and prices."

Washington Environmental Council
Seattle, Washington

Response: Installation of insulation in homes has been demonstrated to be cost effective and represents a significant potential energy resource. This is also true in the case of several types of solar applications, such as solar water heating and passive solar space heating. Technological development of additional solar applications will futher increase solar's potential. Still, solar power has not yet been widely adopted by consumers and it is difficult to predict the extent to which it will be adopted in the future. Utility support of solar applications could foster development of solar's potential; however, to count on solar power for purposes of load forecasting would be premature at this time.

Comment: "Had an alternative assumption regarding utility purchase (or financing) of on site use of solar systems been utilized, the projections of increases in air pollution caused by fuel substitution due to higher electrical rates would be significantly different. Since such a program would mitigate the increased air pollution expected as a result of higher electrical rates, it should be included in the final EIS."

Washington Environmental Council
Seattle, Washington

Response: The cost of solar generation in relation to thermal generation makes this assumption inappropriate at this time and its adoption would result in an underestimate of air pollution impacts.

Comment: "It is not clear why the cost of Bonneville's Second Powerhouse was used to calculate the incremental (marginal) cost of energy. Subsequently, the use of a marginal energy charge of 17 mills appears to underestimate BPA's true incremental energy charge.

Appropriately, only that portion of Bonneville's Second Powerhouse devoted to energy (as opposed to capacity) should be melded with the cost of energy from the net billed plants."

Washington Environmental Council
Seattle, Washington

Response: The second powerhouse at Bonneville Dam will provide the Federal Columbia River Power System with incremental capacity and energy. Accordingly, costs associated with the production of capacity and cost associated with production of energy were used to calculate the long-run incremental costs of capacity and energy, respectively.

Organization and Methods

Comment: "The BPA is required to consider alternatives outside the area of the agency's expertise and regulatory control as well as those within it.

The draft EIS should examine, evaluate and describe impacts of a whole range of alternatives which should include:

1. Retention of existing rate structures and schedules with an across the board increase to all classes of customers.

2. Retention of existing rate structures and schedules with selective increases to specific customer classes.

3. Development of new modified rate schedules which would:

(a) limit the rate increase to BPA's direct service industrial customers; (b) provide a modified Long Run Incremental Cost approach with constraints to establish cost indicators for new power costs; (c) provide a lifeline or baseline type approach, for mitigation of impacts to the domestic users, possibly developing an inverted rate structure, and/or reallocating the revenue requirements to different classes, to make up for lost revenue.

The EIS purports to consider a variety of rate design alternatives including an average cost rate structure, a marginal cost structure via a long run incremental cost approach, a time differentiated average cost rate structure, a share-the-savings rate structure, interruptable, baseline, capacity rates, lifeline rates, and inverted block rates. It lists the alternative rate designs in its Executive Summary along with impact categories. The designs purportedly studied were set up as alternatives to the proposed rate changes. However, the draft EIS actually contains only the most cursory analysis of various types of rate structure alternatives.

The alternative rate designs most likely to limit the impact on low income people received no analysis at all; i.e., the baseline rates, and lifeline rates. These are merely mentioned in the EIS.

BPA did attempt to carry out a valid LRIC study. The "Study" was purely theoretical in nature and did not develop constraints. As of this date there have been no pure LRIC structures implemented. Because LRIC rate structures in their pure form would develop massive surplus revenues, constraints are required to reduce such revenues. BPA simply carried out a theoretical pure LRIC study; found that there would be surplus revenues; and totally disregarded it without considering proper constraints. The LRIC study was not to develop constraints along with the rate structure and it lacked a detailed analysis regarding the effects it would have on the environment.

Generally the draft EIS does not develop the proposed alternatives into operable rate schedules and structures and describe the effects and impacts in comparison to BPA's proposal. In essence BPA considered no alternative to their proposal, but merely cursorily examined various rate theories."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: Chapter V of Bonneville's final EIS analyzes various revenue level impacts ranging from a 0 percent increase alternative to an 895 percent increase alternative and includes other alternatives at the levels of 30 percent, 83 percent, 90 percent, and 195 percent. Many rate design alternatives are analyzed in Chapter VI of the final EIS.

Bonneville could not consider every conceivable alternative in the final EIS. If Bonneville were to attempt to combine the array of revenue level alternatives with all rate design alternatives, a virtually infinite range of rate schedules could be developed. This infinite range would be nearly impossible to include in the EIS. Nor would such a presentation meaningfully aid decisionmaking because an infinite number of alternatives would be more than the decisionmakers could rationally comprehend. Thus, Bonneville chose to discuss rate level and rate design separately in terms of ranges of impacts for various revenue levels and alternative rate design issues.

The final EIS does include a discussion of the baseline concept. It may be found in Chapter VI, pages 39-44. Furthermore, the rate design alternative of constrained long-run incremental costs is discussed in Chapter VI on page 6. It should be noted that the final proposal reflects the results of the long-run incremental cost study. The Reserve Power Rate Schedule, EC-9, was developed directly from the LRIC study. The incremental cost of capacity, which is reflected in the rate, is based on the costs of new transmission facilities and hydroelectric peaking facilities at existing FCRPS generating plants. Incremental cost of energy is based on the energy costs associated with the net-billed thermal plants and the second power house at Bonneville Dam. Firm Power Rate, EC-8, and Wholesale Power Rate for Industrial Firm Power, IF-2, reflect the results of the LRIC study through an adjustment of capacity costs. The incremental cost relationship between capacity and energy is changing as BPA begins to purchase the output of the thermal plants. By comparing the results of the FCRPS Cost-of-Service Analysis with those of the LRIC study, these changing relationships become evident. These studies show that though all costs are increasing, the cost of supplying energy is increasing at a faster rate. Therefore, all surplus revenues from nonfirm energy and from capacity sales have been credited to capacity costs, first to the offpeak period and then to the summer seasonal period.

Comment: "Although the statement is generally well done, it may be difficult for the layman to read and uderstand. For example, terms such as "net-billed" and "pass-through sales" should be defined."

U.S. Department of Interior
Washington, D.C.

Response: An attempt has been made in the Final EIS to avoid the use of terms which would be confusing to lay readers and to clearly define terms which may be unfamiliar.

Comment: "Reviewers of this EIS are frequently referred to BPA's Draft Role EIS for expanded treatment of the topics covered. Yet, by the BPA's own admission the Draft Role EIS is undergoing substantial revision. As a result, reviewers of this EIS are being referred to a document which may contain false premises, incorrect or incomplete data and unsupportable assertions. While the WEC acknowledges the impracticality of reproducing the exhaustive detail of the Role EIS, we believe that the use of its draft version as a reputable reference is somewhat questionable."

Washington Environmental Council
Seattle, Washington

Response: The BPA Draft Role EIS has been referred to only when it was felt that it represented the best available source of information on an issue.

Comment: "It (EIS) does not provide either site or region-specific information on the environmental impacts of the proposed rate increase.

Although the type of environmental impact information we believe this E.I.S. should contain may be quite difficult to produce, we recommend this rate increase and any alternatives to it be subjected to input-output analysis in order to determine socio-economic impacts by sector and geographically. Such an analysis would permit verification of the equity of the proposed rate increase or any alternatives to it."

Seattle City Light
Seattle, Washington

Response: Bonneville is not aware of the existence of an input-output model which would permit the type of analysis suggested. The development of such a model and the collection of data needed for its use is beyond BPA's ability to accomplish given the time and personnel constraints within which the agency must operate.

Comment: "The economic impact information that is provided is presented in a manner difficult for the average reader to follow."

Seattle City Light
Seattle, Washington

Response: Significant efforts have been made to simplify and better organize information dealing with economic impacts. Consideration of economic impacts has also been separated from material dealing with other types of impact.

Comment: "We have found the format of this document to be quite confusing. The discussion of the proposed rate increase is burried in the document, preceded by four chapters of a technical discussion of rate making principles. While inclusion of such theoretical information is laudable, it might best be integrated into the analysis of the rate increase itself. As it is, the information is presented in such a disjointed way as to make it a nearly impossible task for the interested but non-expert citizen to decipher. Substance and integrated analysis is overwhelmed by theory and hypothesis to the point that very little analysis appears to have taken place. Theoretical discussion and hypothetical options cannot substitute for thorough analysis of real options."

Seattle City Light
Seattle, Washington

Response: Substantial changes have been made in the EIS to improve both the organization and content of the material presented. The Final EIS minimizes theoretical discussion in favor of quantification and discussion of the impacts related to BPA's proposed wholesale power rate increase or alternatives thereto.

Comment: "We believe the draft EIS falls abysmally short of the objectives and requirements of the National Environmental Policy Act of 1969, (NEPA), 42 USC 4321, et seq. 1970, and the relevant Council For Environmental Quality (CEQ) guidelines for the content and preparation of Environmental Impact Statements.

The proposed draft EIS must have extensive rewriting and be resubmitted in order to meet the objectives of NEPA and the CEQ guidelines. Agencies are required by CEQ guidelines to, '. . . make every effort to convey the required information succinctly in a form easily understood, both by members of the public and by public decision makers . . . .'1/ The approach taken by BPA requires the reader to piece together disjointed and unrelated sections in order to attempt any analysis of the proposal and the limited options considered. However, even after this considerable effort, the draft EIS is simply inadequate to allow the decisionmaker to reach an objective and appropriate decision."

People's Organization for
Washington Energy Resources
Olympia, Washington

1/ 40 CFR S 1500 8(b).

Response: Substantial steps have been taken to simplify and better organize the information presented in the Final EIS. The central issues of revenue level and rate design are clearly distinguished with considerable treatment being given to each. Also, the analyses identify a specific set of alternatives to BPA's proposal and provide equivalent comparative quantitative analyses of the proposal and alternatives to it.

Comment: "BPA not only refused to examine meaningful general alternatives, but it also failed to examine meaningful alternatives within the context of its average cost of service method which is the basis of its proposal. It adopts, at p. 37, the methodologies used in its average cost of service studies by a conclusory statement, that 'the methods selected during each of the steps are appropriate to the system.' At the same time it fully admitted that other methods could have been used without describing them. It did not describe the other alternatives or provide a meaningful justification for the method selected. It then went on and adopted by a mere conclusory statement, a causation approach (p. 27), rejecting the traditional industry fixed cost/variable costs method for classifying generation costs to capacity and energy, without describing the effects of the fixed cost/variable costs alternative. It then arbitrarily established, without meaningful justification through its causation approach, a classification of hydro power at 59 percent to capacity and 41 percent to energy, and thermal at 10 percent to capacity and 90 percent to energy. BPA then chose the 'rolled in method' for allocating transformation costs in a conclusory fashion without examining any alternatives, including the present system which divides the costs into components."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: Bonneville's consideration of alternatives regarding these topics has been expanded in the Final EIS (see Chapters III and VI). In these chapters the alternative methods for developing cost-of-service for classification and allocation are discussed. A method was selected by BPA from the alternatives that were evaluated and the reason for selection of the alternative is discussed. The basis for the conclusions which are reached are explained. The same approach was used in examining the question of a separate charge for transportaton. More detailed discussion of the rationale related to each of these issues is contained in BPA's "Staff Evaluation of Official Record", July 1979.

Rate Level

Comment: "In at least one case we believe the economic information presented to be misleading. On page 52, it is stated that the 1980 costs for Seattle would be 4.03 percent higher with the 90 percent BPA rate increase than without it. Although the total rate increase would amount to 90 percent, the effective increase for Seattle City Light would be 137 percent."

Seattle City Light
Seattle, Washington

Response: The analysis in question was based on the assumption of a 90 percent increase in both demand and energy charges and was not intended to reflect the effects of BPA's actual proposal, presented in Chapter V of the Draft EIS. This assumption was not made sufficiently clear to avoid confusion, however. The analysis of impacts on utility costs has been replaced in the Final EIS by material presented in Chapter V, Section A.1.d.

Comment: "Bonneville's Public Statements seem to give a wrong impression as to the impact of their proposed 90 percent revenue increase on our customers. In Bonneville's EIS, it is inferred that the effect of a 90 percent revenue increase would only amount to a 27.4 percent increase in average retail rates. The facts are that Bonneville's proposed 90 percent revenue increase will increase Snohomish County PUD's purchased power bill by 103 percent. This, in turn, could require approximately a 50 percent increase in the retail rates to our customers."

William G. Hulbert, Jr.
Verbal comment made during the Wholesale Power Rates Public Comment Forum, Seattle, Washington, November 13, 1978.

Response: The 27.4 percent figure was based on the average increase which would have been anticipated in the total costs of BPA's preference customers in the event of a 90 percent increase in their wholesale power costs. The impact would differ from utility to utility due to differences in the proportion of cost devoted to purchasing power from BPA. This information has, however been deleted from the Final EIS because the results do differ significantly from utility to utility.

Comment: "The draft EIS describes at pp. 50-53, a projection of the monetary effect the wholesale rate increase will have on individual utility rates. The draft EIS arrives at an average 27 percent retail rate increase. It describes its projections as essentially worst-case situations, but no real methodology was used and the basis for its projection is inadequately described. Therefore, the draft EIS does not provide detail sufficient to support the projected retail rate increase.3/ The EIS attempts to establish and emphasize a 27 percent average retail rate increase by calculating the retail rate increase percentage on what it projects the affect the wholesale rate increase would have on the individual rate structures of the utilities as of 1980. It admits that the individual utilities will have increased rates by 1980 regardless of the proposed BPA wholesale rate increase because of their own inflationary factors. Therefore the 27 percent average retail rate increase put forth by BPA is misleading because it does not refer to a percentage increase in relation to today's rates, and does not analyze the harm which will be inflicted in extreme cases."

People's Organization for
Washington Energy Resources
Olympia, Washington

3/ Testimony by Seattle City Light and Snohomish County PUD #1, two of the largest customers indicates the projections vastly understate the impact on consumers.

Response: As indicated in the preceeding response, the section in question has been replaced by Section A.1.d of Chapter V in the Final EIS. Additional material on projected increases in 1980 retail rates is included in Section B. of Chapter V.

Rate Design

Comment: "The second question the WEC investigated involved the allocation of the higher cost of power among BPA's customers. In general, we feel the proposed rate schedules fairly distribute these costs. The cost-of-use charges, such as differential rates for "on-peak" and "off-peak" purchases, should result in more efficient use of both energy and capacity. However, the WEC feels that further efficiencies in the form of energy conservation could be achieved through additional rate related measures.

Under the present proposal BPA will continue to set its rates based on the average cost of the power it markets. Subsequently, BPA's customers will continue to pay less for additional electricity than it is costing to produce it. As a result, conservation measures which make economic sense from a system-wide basis will remain uneconomic to the individual consumer.

Two possible approaches, short of setting rates 'at the margin', exist for dealing with this situation. First, BPA could establish conservation guidelines for all purchases of its power. These guidelines could be formulated for each customer class or consuming sector with actions producing the most cost-effective and largest savings addressed first. The adoption and implementation of these guidelines would be encouraged through the establishment of a surcharge on the power sales to non-complying utilities or industries. This surcharge could increase gradually in severity with time.

A second alternative is the establishment of a two-tiered pricing mechanism with one tier containing low cost FCRPS resources and the second tier containing the higher cost 'net-billed' resources. Utilities and direct service customers of BPA could receive a fixed allocation from the first tier based on their present load. Additional needs would be supplied from the second tier.

The rationale for this approach is that new loads (i.e., load growth) would be met using new resources and subsequently be paying 'new resource' costs. This approach presents utilities and direct service customers with a considerable incentive to remain within their first tier allocation for as long as possible, and, of course the implementation of an effective conservation program is one means for accomplishing this goal."

Washington Environmental Council
Seattle, Washington

Response: The development of conservation guidelines by BPA for use with rates would require careful analysis to insure both efficiency and equity. Bonneville is currently engaged in exploring a variety of conservation options, some of which may in the future be associated with rate incentives.

Bonneville has also completed some preliminary two-tier rate analyses which provide information pertinent to WEC's second alternative. See sections C.7 and C.9 of Chapter VI for further discussion of these issues.

Comment: "We believe that there is one critical element missing in the DEIS which merits additional analysis and discussion in the final environmental impact statement. Page 86 of the DEIS refers to the September 1977 PNUCC Task Force 8 Report on future power system operations and notes that the system in the years 1989 and beyond would have severe operating problems. Our review of the PNUCC Report leads us to believe that the system may, in fact, be physically inoperable.

The discussion on pages 86-87 indicates that the implementation of peak load/time-of-day pricing could significantly alleviate this problem. However a couple of critical questions remain unanswered by the discussion. These include: (1) Was the analysis of peak load pricing's impacts done for such pricing at the wholesale level, at the retail level, or for both? (2) Is the projected chage in power system demands/loads sufficient to elminate the problems projected by the Task Force 8 Report? (3) If not, what additional actions could BPA take, as the manager of the Federal Columbia River Power System, including requiring retail peak load pricing, to insure shedding on a daily/hourly basis?"

U.S. Environmental
Protection Agency
Seattle, Washington

Response: The discussion on pages 86-87 of the Draft Environmental Impact Statement indicates that the implementation of diurnal time differentiation could significantly alleviate the problems of excessive daily load swings, insufficient water and regulation capability to carry sustained peaking, and intolerable fluctuations in pool tailwater levels. This conclusion was based on the assumption that a diurnal differential was implemented at the retail level. This discussion was included in the DEIS as an example of potential benefits of this type of pricing scheme and not as a discussion of the problems enumerated above. Though BPA has proposed a diurnal differential in its capacity rates to utilities and industries, Bonneville does not expect that this differential will be reflected in all retail rates at this time due to metering problems, although it could be adopted for some large customers. Alternatives to be considered as remedies to the problems discussed in the DEIS could include load management by direct controls or installation of oil-fired combustion peakers.

Comment: "Are the reserves provided by DSI's worth $40 million? Why aren't the increases in EC-8 charged for the reserves in the ratio that DSI reserves support capacity or energy?"

Clark County PUD
Vancouver, Washington

Response: The availability credits determined under the August IF-2 wholesale rate proposal were not based on the value of reserves provided by the DSIs. Instead, the $40 million dollar figure was derived by increasing the existing credit in proportion to the rate increase to industries. Although Bonneville staff is concerned with the value of these reserves, it has not yet attempted to estimate this value.

Bonneville believes that these reserves are most likely to be needed to provide energy reserves and thus it is more appropriate to charge this expense to energy than capacity. However, these reserves can also be called on to provide capacity reserves and Bonneville is considering reflecting this in later proposals.

Comment: "The IF-2 rate should be made available to wholesale utility customers for pass-through to their own industries. Of course, if that rate were made available to utilities, the utilities would expect that the same restrictions and conditions would apply to their customers being served by this rate as apply to BPA's direct-service industrial customers."

Public Power Council
Vancouver, Washington

Response: Although BPA has not traditionally made the industrial rate available to its utility customers for pass-through sales, such action is not prohibited in any way. Bonneville would, of course, need to have total control over the industrial load in order to offer such a rate to its preference customers for pass-through sales. Any interested utility should discuss the matter with the Administrator.

Comment: "There is no limit to the number of plans or methods that can be used to allocate costs between capacity and energy. There is no one indisputable practice; there is no one court decision that establishes procedures, nor are all power supply systems identical. We are an energy short region and the BPA rate proposal addresses itself to this problem. The assignment of costs to energy and capacity by BPA is fair when viewed for this position. It reduces rate disparity among preference agencies and takes a giant step toward the return to the postage stamp method employed for years by Bonneville."

Inland Power and Light Company
Spokane, Washington

Response: See Chapter VI, Section C.1.

Comment: "PPC suggests that BPA evaluate thermal generation with more emphasis on capacity than on energy, a 10-90 percent split is proposed by BPA. PPC also suggests that BPA arbitrarily assigned other revenues and costs in order to shift the emphasis on rate increase to energy. While the EC-8 rate proposed by BPA is not perfect, I would hesitate to support a major change favoring one group of customers without knowing the associated impact on remaining BPA customers. The studies being conducted by R.W. Beck and Hittle and Brown will hopefully, in their conclusions, consider the impact to nongenerating utilities, as well as to the generating utilities and the utilities with heavy irrigation loads."

Lewis County PUD
Chehalis, Washington

Comment: "BPA relates that it apportioned costs in relation to the causes underlying the construction of plants. The allocation of 90 percent of thermal plants is excessive in terms of the scheduled capacity.

The cost of providing energy from thermal plants may not be the same throughout the year. If each hour is to be supplied at 100 percent of nameplate, the plant is supplying a firm amount of peak each hour equal to the energy provided. Why not allcate the costs at 50 percent to peak and 50 percent to energy?"

Clark County PUD
Vancouver, Wahington

Responses: Bonneville has carefully considered the most appropriate way to classify costs between demand and energy. This topic is thoroughly addressed in BPA's "Staff Evaluation of Official Record", July 1979 (available on request through BPA's Branch of Rates).

Comment: "Grant (County PUD) believes that the fundamental principles of rate setting should be (1) rates based upon average costs, (2) no rate disparity within customer classes, and (3) stability of rate design from one rate adjustment to the next.

Rates should be designed so that long-term trends in power costs are recognized and phased in as they occur. Utility planning is done based on at least a 35 year life of the facilities. One major factor in facilities planning is its effect on other costs. Proper decisions cannot be made if costs cannot be reasonably estimated for at least more than one or two years."

Seattle City light
Seattle, Washington

Comment: "PPC participants have an overriding concern for stable rate structures. BPA and PPC participants are aware of the need for long range planning in order to match resources and projected demand. Such long range planning must include rate design planning which will enable wholesale power customers to deliver electric power to their consumers at the lowest possible cost. If BPA fails to maintain consistency in its own rate designs, its wholesale power purchasers' long range planning is disrupted. Such consistency is especially critical in light of BPA's annual rate review authority beginning after 1981. The Public Power Council strongly urges BPA to adopt basic rate structures which it will retain into the foreseeable future."

Public Power Council
Vancouver, Washington

Comment: "In preparing rate structures, we feel that BPA should take into consideration stability of their rate structures from one rate review to the next. Seattle, along with all other utilities, must make long-range plans to match its resources, transmission and distribution facilities to its projected demand and do it in the most economical manner. These long-range plans must take into account the BPA rate structure. If BPA fails to maintain consistency in its rate design, the utilities long-range plans can be adversely affected which will result in substantial negative monetary impacts on its customers. Such consistency is especially critical now that BPA has annual rate review authority after 1981.

In order to allow for continuity in utility planning and minimize adverse financial impacts for their customers, we strongly urge BPA to adopt and retain a basic rate structure which can be used into the foreseeable future."

Seattle City Light
Seattle, Washington

Responses: One objective of rate design is stability of rate structure. However, rate design must also consider revenue requirements, conservation, equity, economic efficiency, understandability and ease of administration.

Comment: "The significant change in approach to allocations between demand and energy costs raises questions as to how well the assumptions underlying the 'cost-causation' approach reflect economic realities. Does a utility purchasing power from BPA at a high load factor offer economic advantages in meeting regional load requirements, and if so, to what extent? We believe that there are significant cost benefits, and that these benefits should be reflected in the aggregate power costs to a utility. Recognition of these benefits are substantially reduced, if not lost, as compared to the present rate form, as illustrated in the estimated 'Rates to Individual BPA Customers, 1980' presented on pages 117 through 121 of the Impact Statement. We believe that this issue has not been adequately addressed.

The introduction of a rate form reflecting an alteration in the energy-demand cost ratio from approximately 53/47 percent to 71/27 percent would significantly affect the status of past commitments by individual utilities for development or purchase of base load or peak load power resources. Such a change would have an adverse effect on the present planning activities of utilities in the region and would be detrimental to the stability of present planning and development efforts."

City of Tacoma
Tacoma, Washington

Response: The final proposal reflects a different relationship between capacity and energy than was contained in the draft EIS. Bonneville believes that the changes for energy and capacity should reflect the marginal costs of providing the services.

Comment: "Economic efficiency is not always compatible with marginal cost concepts. The development stage of marketing any product requires an average cost concept to be competitive with established products. Introduction of new products at marginal costs could stop the widespread acceptance of a product that could be more efficient economically than existing products. An example is the development of solar energy. If average cost pricing is used, it is still higher than other average cost products. If solar were priced at marginal costs, solar would not be developed as existing energy sources would be fully utilized before solar or any new energy source would be sought."

Clark County PUD
Vancouver, Washington

Response: This point is well taken and the text of the statement no longer asserts that marginal cost will necessarily result in maximum economic efficiency.

Comment: "We request additional explanation by BPA of the failure to differentiate energy costs between summer and winter periods. We would like to know why, in the last rate increase, the winter energy costs were apparently nearly double the summer energy costs, and now no seasonal cost vaiation can be identified."

Grant County PUD
Ephrata, Washington

Response: Bonneville has modified its rate proposal to reflect assignment of hydro storage costs to the winter period. Section C.2. of Chapter VI provides information on this issue.

Comment: "The seasonal and time-of-day demand charges are based in part on costs related to loss of load probabilities. We would note that as the availability of thermal resources increases, loss of load probabilities would be more evenly distributed over all months, reducing justification for cost differentials by month."

City of Tacoma
Tacoma, Washington

Response: Probability of negative margin (PONM) data for the years 1980 through 1986 was used as an aid in the selection of seasonal periods for capacity costs. The growing thermal resource dependence of the region was taken into account in the calculation of the PONM data. Changes in such probabilities should be reflected when appropriate in future rate adjustments.

Comment: "In regard to the time of day features of the demand charge in the proposed rates, the District is uncertain as to Bonneville's intent. The District understands that Bonneville neither expects nor desires any shifting of load into the off-peak hours. The District requests that Bonneville re-evaluate the benefits of this aspect of its proposed rates.

The District has adopted a seasonal energy retail rate structure for certain classes of customers in response to Bonneville's last rate change. The elimination of a winter-summer energy rate differential will adversely affect these customers. For the purpose of rate stability such a drastic change in rate form should be ramped-in over a period of time, if adopted."

William G. Hulbert, Jr.
Verbal comment made during the Wholesale Power Rates Public Comment Forum, Seattle, Washington, November 13, 1978.

Response: The purpose of the capacity cost differential it to reflect cost differences. Bonneville has reconsidered the time-differentiated feature of its proposed EC-8 energy rate and has concluded that cost of service differences warrant the retention of this rate feature. The proposed elimination of the seasonal differential from BPA's firm power rate has also been re-evaluated and Bonneville has proposed a seasonal energy differential. The proposed differential is discussed in Section C.2 of Chapter VI.

Comment: "Seasonal differentials continue to increase the rate disparity between generating and non-generating utilities."

Public Power Council
Vancouver, Washington

Response: The impact of seasonal rate differentials is discussed in Chapter VI, Section C.2.

Comment: "With respect to the time differentiated daily demand charges, we fail to see its purpose. With such a long peak period (15-hour peak period), there is little incentive or possibility to shift load to reduce peak loading. Further, BPA has stated in its time-differentiated pricing analysis, that it does not intend to induce peak load shifting with a demand charge differential. If this is really the case, and BPA does not intend to shift peak, then it should not introduce a daily demand differential which will, no doubt, create some confusion and administrative delays."

Seattle City Light
Seattle, Washington

Comment: "The (proposed) rate structure should encourage a diminishing peak demand and should not penalize users who switch from peak demand periods. The idea of a peak and non-peak rate is good. The peak rate should be large enough to encourage users to shift their usage to non-peak hours. This would benefit our diminishing fish resources by evening out flow rates on the rivers where hyrdo projects are located."

Steven B. Rubin
Seattle, Washington

Responses: Bonneville recognizes that there are many potential advantages in adopting time of day rates. Foremost is the potential to achieve the higher degree of equity among customers by developing rates that more accurately track costs. The idea is to charge according to cost incurrence. Those customers whose demands for electricity impose costs on the utility should be the customers who bear the burden of those costs. Bonneville's rates also encourage customers to take demand outside of the peak period by having no demand charge for off peak capacity.

The method used to develop BPA's time differentiated pricing study is but one of many methods that could be employed to conduct this type of analysis. Bonneville used the following criteria to establish the costing/pricing periods: (1) The number of periods selected should be feasible to administer; (2) hours or months which have similar costs should be combined into like groups; and (3) the periods chosen should be broad enough to allow for shifts in loads without shifting the peaks outside the peak period. With these criteria in mind, diurnal periods were chosen by examining the average ratios of hourly generation to daily peak generation for each day of the month for operating years 1975-1978. An analyses of the firm loads and probabilities of negative margins, indicated that over 99.9 percent of all probabilities of negative margins occurs during the day with loads that are 90 percent or greater of the daily loads. After examining each individual month for all individual hours, it was concluded that the appropriate peak period is the 15 hour period from 7 a.m. to 10 p.m. The 9 p.m. to 10 p.m. hour came closest to falling outside the peak period. However, it was included because one of the criteria for establish costing pricing periods is that the periods chosen should be broad enough to allow for shifts in loads without shifting the peaks outside the peak period. The 9 p.m. to 10 p.m. hour during the years analyzed, over many months had a ratio of .90 or higher. Therefore the time period 7 a.m. to 10 p.m. adequately satisfies the three criteria for establishing costing pricing periods.

Comment: "BPA has stated in its Time-Differentiated Pricing Analysis that it does not intend to induce peakload shifting by its adoption of a daily demand charge differential. The selection of a 15 hour peak period, Monday through Saturday, is consistent with that intention. Such a long period will provide little incentive for any load shifting to reduce peak load. However, if BPA expects its utility customers to introduce their own time-of-day demand rates that follow BPA's demand rates in order to reduce peak load, the daily peak period should be reduced one hour on each end. We are not certain that the peak load can be reduced by this approach, but the shorter peak period would give more incentive to ultimate users to shift some peak load off-peak. But if BPA really does not expect to reduce its daily peak by a daily peak pricing rate differential, it should not introduce a daily demand differential."

Public Power Council
Vancouver, Washington

Response: The time differentiation in BPA's proposed EC-8 rate is based on the concept of cost causation. That is, because additional energy and capacity are required to meet imcreased energy and peakload demand during peak periods, the costs of supplying that energy and capacity are higher than during offpeak periods. Therefore, those customers whose demands for electricity impose costs on the utility should be the customers who bear the burden of those costs.

Comment: "The conclusion that 'time-differential rates should produce some effect on household use of electricity' may not materialize. Only if the rates proposed force a change in retail rate structures will there by any change. The only residential response that will happen, uniformally, is a decrease in consumption, primarily off-peak, that is in response to the increased costs. The expected off-peak reduction will probably be reduced nighttime heating.

There is, relatively, no incentive to reshape retail rates to reflect new BPA rate structures. These utilities that responded to the last BPA rate structure change (adding transformation charges) now find that they built or bought BPA sutstations needlessly. There is no guarantee that if utilities added demand metering and clocks for dual rate structures, that BPA would not change the rate structure again.

As indicated in BPA's discussion of baseline rates (Chapter VI, Section C.7), Bonneville is well aware that utilities may not choose to reflect BPA's rate design features in their retail rates. This would, of course, prevent BPA from influencing load patterns via time-differentiated pricing. However, BPA's purpose in instituting a time-differentiated rate was to reflect cost of service objectives rather than to achieve load management."

Clark County PUD
Vancouver, Washington

Response: The time differentiation in BPA's proposed rates is based on the concept of cost causation. That is, they are designed to achieve cost-of-service objectives rather than load management. If retail utilities do not institute time-of-day pricing then BPA's proposed time differentiated rates would have little effect on the household diurnal pattern of use of electricity.

Comment: "The EC-8 rate proposal is inadequate as it has no charge for the off-peak demand period. The shifting of $60 million in costs incurred during the off-peak period to other rate factors is not in line with charging for services rendered. Secondarily, there is no financial control over exceeding equipment demand limits during off-peak hours.

The shifting of capacity costs to energy is not appropriate under cost of service principles nor needed to signal rate of growth for energy costs. Instead, it will give consumers false signals on the costs of off-peak capacity."

Clark County PUD
Vancouver, Washington

Response: Bonneville's goal in eliminating the off-peak capacity charge was to reflect the fact that this service causes no additional cost to Bonneville and that the cost of energy is increasing much more rapidly than is the cost for capcity.

Comment: "Is it not true that the cost-of-service study conducted by Bonneville did indeed reflect a higher demand charge for industrial customers than for preference customers, and further, was there not an arbitrary decision to equalize the two demand charges in the preparation of the EC-8 rate and the IF-2 rates? It follows that the preference customer will be paying more than his fair share in demand charge, all as a consequence of a leveling of load factors. We would urge that no arbitrary equilization of demand charge between two types of customers be permitted to continue and that the proposed rates be corrected to reflect an actual cost-of-service requirement."

Clallam County PUD
Port Angeles, Washington

Response: The cost of service analysis did show higher capacity costs for IF-2 customers than for EC-8 customers. The rates for IF-2, EC-8 and F-7 were levelized to reflect the significant benefit the IF-2 customers provide to Bonneville by taking energy during off-peak hours. This allows Bonneville to accept return of energy during these hours from other customers and to purchase the output of base load thermal plants which operate around the clock.

The impact on preference customers' rates because of that adjustment is a $.02 decrease in their monthly demand charge. Bonneville's proposed rates are based on a number of factors including repayment criteria, cost-of-service, value of service, equity, efficiency, rate continuity, and ease of administration.

Thermal Plant Financing

Comment: "New high cost thermal power should be heavily charged against peak demand users."

Steven B. Rubin
Seattle, Washington

Response: Bonneville's thermal power is generated primarily to meet BPA's energy requirements. As a result, the entire cost of thermal power should not be charged against peak demand users.

Comment: "The report states that the BPA expansion, and rate increase request was based on a forecast prepared by utilities of the region. Those forecast needs have been overestimated in the past.

With the 90 percent rate increase request by BPA, the ratepayers are being asked to pay for plants '<u>whether</u> the projects are <u>completed</u> and notwithstanding shutdowns or curtailments that may occur at finished plants'. (Oregonian, November 28,1978)

I believe this is an unacceptable way for BPA to do the public business without the public involvement and awareness of the issues and alternative options."

Joyce Cohen
Lake Oswego, Oregon

Response: The load forecast prepared by the Pacific Northwest Utilities Conference Committee (PNUCC) has exceeded actual loads since 1974. However, the construction of power generation facilities has lagged behind forecast needs to the extent that the region is facing a serious likelihood of power supply shortages within the next 5 years.

Bonneville's contractual commitments to the net-billed thermal plants do require BPA to cover the costs of the plants regardless of their completion or operation. Bonneville does not currently have the authority to enter into any additional thermal plant power purchase agreements.

Bonneville has a public involvement program which will insure that the public will be made aware of and will be included in the BPA decisionmaking processes.

Comment: "Scope of rate increase should allow for increase in transmission costs, thermal-coal costs, hydro costs. The rate increase should not cover costs for thermal-nuclear plants. This variation of the No-Action Alternative (page 48) leading to default on bonds and difficulties in selling new bonds should be taken.

It is far better to write off the monies spent to date than to throw more money into unproven and costly overrun prone technologies."

Steven B. Rubin
Seattle, Washington

Response: Bonneville operates on a "self-financing" basis, i.e., it receives no appropriations from Congress and must pay all of its operating costs from revenues. Bonneville is authorized to sell bonds to the U.S. Treasury to raise funds to finance the construction of new transmission facilities. BPA is obligated by statute (Bonneville Project Act and Federal Columbia River Transmission System Act) to set its power and wheeling rates at "the lowest possible rates to consumers consistent with sound business principles" that will fully recover the cost to the Federal Government of generating, purchasing, transmitting, and marketing electric power, including the amortization of the Government's investment in power facilities, with interest. The cost of the nuclear plants is included under power purchases.

Although Bonneville actively supported the WPPSS financing proposal which would have resulted in a smaller revenue increase in 1979 and larger increase in later years, with a lower long-run revenue increase, that proposal failed to receive the necessary unanimous approval of all participants in the WPPSS nuclear plants.

Comment: "The use of cost estimates for the WNP #1 - 3 and Trojan facilities based on a 75 percent capacity factor is misleading. Actual values for Trojan should be used and capacity factors consistent with PNUCC's Task Force 8 Report should be used for the WNP cost projections."

Washington Environmental Council
Seattle, Washington

Response: Thermal plant capacity factors can be subject to relatively wide variations. The 75 percent used in the Draft EIS is not an unreasonable estimate and is not considered by BPA to be misleading. Plant factors are expected to increase with time and then decline as the plants age. For planning purposes most plants are assumed to operate over the long run in the range of 60 to 80 percent. Studies of existing nuclear plants have shown that this is a reasonable range, although there are some that have both higher and lower plant factors. Thus, to use the first two or three years as representative capacity factors for Trojan may result in an underestimate of future performance.

Comment: "You state that WPPSS could finance IDC through bonds. You do not state any impact from that possibility. Is it true that bonds can be issued?

Is there enough security and bond coverage available? What will be the effect on future costs of the net-billed plants? Will the costs have to be absorbed by the net-billed participants, and will this result in higher power costs to them than the BPA proposed increase? For clarity, a statement of the impact of Item 2 should be included within Item 2 and not be carried in the last paragraph of this section.

This also carries no impact from the suggested action. Items 1, 2 and 3 are just not being treated equally."

Clark County PUD
Vancouver, Washington

Response: The WPPSS participants have failed to approve the issuance of junior lien bonds to finance debt service on the net-billed plants during construction. Nevertheless, expanded discussion of this issue is provided in Chapter III, Section B, in addition to the material in question (Chapter II, Section D. 4. d).

Comment: "The BPA report states that over 72 percent of the 90 percent rate increase requested is due to decisions made to pay for acquiring a share of several new nuclear plants in Washington State as well as Trojan.

When, Where and by Whom were the decisions made to obligate the ratepayers of the Northwest to such expensive generation of energy?

How was the public included in such basic policy questions which we as rate payers must bear the primary consequences?

BPA should not be allowed to make such decisions until the agency can demonstrate that it can effectively control and monitor the costs of building the WPPSS nuclear generators which, according to a survey by the U.S. Department of Energy, are costing 30 to 50 percent more than the national average or other such projects.

We are now told (Oregonnian Nov. 29, 1978) that the supply system (WPPSS) 'will be more aggressive in telling its' own story, ... by sending managers and technical people into communities to explain the construction and generating program.' Who will document the costs to us the rate payers of the Northwest, the price of such 'publicity' efforts by WPPSS? BPA should not allow such waste of taxpayers and ratepayers money for advertising purposes."

Joyce Cohen
Lake Oswego, Oregon

Response: Authorization for the Hydro/Thermal Power Program was granted by Congress, wherein the public was included through the actions of their duly elected representatives. Bonneville has now instituted a public involvement program designed to provide for more direct public participation in the making of decisions on BPA's actions.

Bonneville has taken several steps to insure increased efficiency in the construction of WPPSS net-billed facilities. These include commissioning of a study of construction costs and practices at the WPPSS Plants and increased participation of BPA's Administrator in meetings of the WPPSS Board of Directors.

Comment: "We believe these net billing agreements are invalid for at least two reasons. First, the net billing contracts are illegal and ultra vires.

Indeed, these agreements account for 72 percent of the proposed 90 percent increase. The net billing agreements have significantly affected the quality of the environment within the meaning of Section 102(C) of NEPA. These agreements have caused severe socio-economic impacts on low income people, as well as other impacts on the natural environment, both subject to the EIS process.

BPA has failed and refused to prepare, publish, circulate and file, as required by 42 USC S 4332 2C, a detailed statement concerning the net-billing agreements. BPA has attempted an incremental decision-making process without the environmental analysis. BPA attempted to avoid an EIS at the point in time when it takes a major significant action, and now assumes a passive posture stating that its hands are tied by the contracts and obligations incurred therein which were entered of its own accord and without an EIS.

The failure of BPA to comply with NEPA regarding the net-billing agreements and its present attempt to push through the resulting proposed rate increase has, in effect, deprived the public of an opportunity to make comments regarding the environmental impacts of the net billing agreements, which are being forced upon the public in the form of a rate increase. At the same time, the failure to comply with the EIS process, at the time of the net-billing agreements, purportedly forbids those who will make the decision on the proposed rate increase from considering avoiding or voiding these agreements. BPA is attempting to effectuate the net billing agreements while ignoring their significant and quantifiable environmental, socio-economic and other impacts."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: Bonneville discussed in detail the impacts of the net-billed plants in its Role EIS (Appendix A, Chapter III, pages 188-200). The net billed plants are of the nuclear fission type. Nuclear plants currently produce electricity at less cost and with fewer land use and air quality impacts than coal-fired plants of the same generating capacity in the Pacific Northwest. Nuclear plants have greater siting flexibility than hydroelectric or coal-fired plants, though they must be located where cooling water is readily available and on geologically stable terrain. They emit minute amounts of radioacitve materials and chemicals. Waste heat rejected to the environment through stream condensers can be dissipated by cooling towers or ponds, but environmental impacts associated with discharged cooling water are a concern, as is competition with other water uses for the large quantities of water which cooling requires.

The potential risk of a catastrophic accident at the nuclear generating plant, radioactive contamination from escaping waste products, diversion of neclear materials by terrorists, and disposal of nuclear waste products are concerns most often raised about nuclear power. These risks may even be more significant for more advanced forms of nuclear power. Because of the increased risk of nuclear proliferation, President Carter has proposed that commercial fuel reprocessing and recycling of plutonium, as well as the commercial introduction of the plutonium breeder reactor be deferred indefinitely.

Because of the limited supply of uranium, light water reactors will be used as interim power resources until they can be replaced by long term renewable energy sources.

Comment: "Each net billing agreement entered into after the effective date of NEPA is invalid as a result of the lack of preparation of an EIS prior to executing that contract. If BPA were released from the agreements and the accompanying obligation to pay the required share of those plants, the EIS admits that there would only be approximately a 25 percent revenue increase required for recovery of the costs of the Federal System. The obligations created by the net billing agreements have drastically increased the cost of service which BPA uses to establish its revenue requirements. Therefore, the basic premise used to calculate the costs required for repayment in the draft EIS is incorrect and invalid because it incorporates the obligations created by the net-billing agreements. However, the EIS purports to not allow the decisionmaker, on the rate increase, to consider the wisdom or efficacy of the net-billing agreements."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: The legality of BPA's net-billing agreements, based upon the absence of an EIS prior to execution of the contracts, is at issue in a civil case pending in the Federal District Court for the District of Oregon (City of Portland v. Sterling Munro, Civil No. 77-929). As BPA has expressed in its answer and briefs in the lawsuit, the net-billing agreements are valid and binding obligations on BPA, consititute a legal obligation of the parties involved and thus, the obligations to the WPPSS plant participants are expenses of the Administrator which are required, under the Bonneville Project Act and the Federal Columbia River Transmission System Act, to be recovered by BPA rates.

Effects on the Physical Environment

Comment: "It is well to cover indirect cost (see pages 36 and 37 of BPA's Draft EIS) of generating electricity and how to collect for damages. There is no discussion on the indirect benefits from generating by electricity and how to collect for benefits. A customer must not be trapped into believing that marginal costs for electricity reflect the costs of turning to other energy sources. Costs of electricity must also include benefits of replacing environment damage from other energy sources."

Clark County PUD
Vancouver, Washington

Response: This comment points to the important fact that in order for marginal cost pricing to result in true social and economic efficiency, alternative fuel sources must also be priced at their true marginal cost.

Comment: "Rate increases that lead to the development of other types of power generation would need detailed environmental scrutiny."

State of Oregon, Intergovernmental
Relations Division
Salem, Oregon

Response: Bonneville has attempted to provide analyses of the effects of increased use of oil and natural gas in Chapter IV, Section D of the Final EIS. It is not anticipated that significant environmental impacts would be created by substitution of other types of fuel which may accompany a rate increase by BPA.

Comment: "It may not necessarily be true as stated in the Draft EIS (page 93, paragraph 5, lines 6-8) that any hydro operation which diminishes the zone of surface fluctuation would generally be beneficial to biological productivity. For example, "An average of 2,795 redds were constructed during the 1967-1976 period. From 1947-58, the average redd count in the Hanford Reach was 433. This increased 5-fold to an average of 2,158 redds for the 1959-1977 period. On Vernita (Midway) Bar the average redd count of 68 (1947-1958) increased 12-fold to an average of 803 redds (1959-1977).

Priest Rapids Dam was completed in 1959. This is obviously an enhancement of the free-flowing stretch due to increased flows from the dam operations. Supposedly the PUD provided full compensation to WDF for lost spawning areas inundated by the dams. Whether or not the spawning channels provided proper compensation is really the responsibility of the fish agencies that made the choice of that kind of 'mitigation.'

The licensed minimum flow of 36,000 cfs below Priest Rapids Dam is greater than unregulated historical low flows. Any increase in the minimum flow will adversely impact peaking capabilities and may very well impact the amount and duration of managed spill for passing juvenile salmonids in the spring."

Grant County PUD
Ephrata, Washington

Response: The Hanford Reach of the Mid Columbia River represents the last significant natural spawning area for salmon on the mainstem Columbia River. Increased spawning activity in this area has been speculated to relate more to the loss of natural spawing areas resulting from dam construction, than from increased minimum flows as released at Priest Rapids Dam.

Significant mortalities to emerging salmon fry and incubating eggs in 1976 and 1977, led to the study of minimum flow levels from Priest Rapids Dam which supported the most viable population of salmon utilizing the Vernita Bar and Hanford Reach. Bavensfield (1978) found that tailwater fluctuations to the allowable minimum of 36,000 cfs exposed salmon nests to dessication, exposure to freezing temperatures and depletion of disolved oxygen. Further, sedimentation of the nests also occurred smothering the inclubating eggs. River fluctuations in general, encouraged adults to spawn in areas above the 36,000 cfs flow level, which could then be dewatered at a later time resulting in significant egg and emerging fry mortality.

During the summer of 1979, the Federal Energy Regulatory Commission ordered four years of study at 36,000 and 50,000 cfs minimum flow levels. The upper level, which would substantially limit the zone of tailwater fluctuations at Priest Rapids, is expected to induce increased and more successful spawning activity, with increased survival of juvenile salmon.

Reference:

Baversfield, Kevin. The Effect of Daily Flow Fluctuations on Spawning Fall Chinook in the Columbia River. Financed by Grant County Public Utility District, Technical Report No. 38, State of Washington, Department of Fisheries, June 1978.

Comment: "What mainstream spawning grounds remain below Chief Joseph Dam that are not below Priest Rapids Dam? Document with aerial redd counds or other data."

Grant County PUD
Ephrata, Washington

Response: As noted in a recent workshop 1/ on the possible listing of upper Columbia River Salmon and Steelhead as threatened or endangered species, there is little if any natural spawning of salmon and steelhead in the mainstem Columbia. Banversfield (1978) identified the 43-mile reach below Priest Rapids Dam as the only spawning area for Fall Chinook Salmon on the mainstem Columbia below Chief Joseph Dam. Identification of all spawning areas on the mainstem Columbia were further identified in the BPA Draft Role EIS, Appendix A, Figure III-49 on Page III-75 and Table III-7 on page III-8.

1/ Summary of Workshop: Biological basis for listing species or other taxa of salmonids pursuant to the Endangered Species Act of 1973." Workshop sponsored by the National Marine Fisheries Service, U.S. Department of Commerce, Portland, Oregon, December 1978.

References

1. Baversfield, Kevin - The Effect of Daily Flow Fluctuations on Spawning Fall Chinook in the Columbia River. Financed by Grant County PUblic Utility District, Technical Report No. 38, Washington Department of Fisheries, 1978.

2. U.S. Department of Interior. The Role of the Bonneville Power Administratiion in the Pacific Northwest Power Supply System; Appendix A. Draft Role Environmental Impact Statement, 1977.

Effects on Low Income and Other Residential Consumers

Comment: "We. . . object to Page 123 and 124, Chapter VI, Mitigating Measures, of the EIS, which implies that if the ultimate users cannot pay their electric power bill, then BPA explains how they can go on welfare, thus adding more expense to the already overburdened American taxpayer. (Enclosed letter from Marvin Crutcher.)"

Harney Electric Cooperative, Inc.
Burns, Oregon

Response: Bonneville is not advocating welfare as a means of paying one's power bill, but welfare does remain a "mitigating measure". Other, perhaps more acceptable, measures would be the establishment of lifeline or baseline rates. These rates would ease the impact of high utility bills on the poor consumer, while not burdening the taxpayer at large.

Comment: "Generally, Indian trust land and Indian communities will be impacted economically in the same manner as others in the Pacific Northwest. It appears obvious that the socio-economic impacts could be significant for low income households. In fact, it is estimated that the Wapato Irrigation Project will have an increased charge of about 40 cents an acre. This is a hardship because the water user charges were determined and officially established before the proposed increase of 138 percent was known."

U.S. Department of the Interior
Washington, D.C.

Response: Bonneville's revised estimates show that the average cost of power to USBIA Wapato will increase by 106 percent rather than 138 percent. Bonneville recognizes that its rate increase may have an adverse impact on some of the Indian communities.

Comment: "The decisionmakers and the public have no real idea of the nature of the deprivation about to be inflicted. They deserve to have the magnitude of impact described in terms of the harm that will be done as well as the numbers of people to be harmed."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: The nature of deprivation has been presented in terms of impacts on income. The consequences of those income effects will vary widely among consumers and will reflect individual decisions which would be difficult to predict. See additional information in Section B.1.b of Chapter V.

Comment: "The draft EIS is completely lacking in detail concerning the impact of the proposed rate increase upon low income domestic users."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: The Final EIS quantifies the impact of BPA's proposed rate increase on all domestic customers in Chapter V, Section B.1.

Comment: "The harm occasioned to low-income people is acknowledged and then ignored. The magnitude of the harm is not adequately studied or quantified. No meaningful effort was made to mitigate this harm."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: BPA considered baseline rates in its revised EIS and quantified the effects of the rate proposal and alternatives thereto on all domestic customers.

Comment: "The draft EIS does not describe and consider an adequate or proper classification of "low income domestic users." The draft EIS (at page 65 and elsewhere in the text) seemingly only attempts to consider the effect of the proposed increase on people in a $3,000 a year income category, which is hardly inclusive of low income populations. No attempt was made to analyze the impact upon the low income populations using other recognized definitional income levels. For example, official Federal/CSA poverty guidelines establish levels of income for families in relation to the size of the family and classification of families as farm or non-farm families. The range of income which is included in the poverty criteria of CSA ranges from $2,690 to $8,240, depending on the size of family and whether the family is a farm unit or non-farm unit.

The draft EIS provides no detail whatsoever regarding the domestic budgets at various poverty levels an the proportionate effect of the increase on these budgets. For example, effects on health and lifestyle through other budget items such as food, clothing, transportation, etc."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: The revised EIS includes a section which discusses definitions of poverty. The actual effect of the revised proposal and alternatives thereto can be quantified, but the impacts on the consumption of other items will vary considerably from region to region and family to family.

Comment: "BPA is required to analyze reasonable alternatives which would mitigate the effects of its proposal. The draft EIS has put forth a proposed rate increase in a manner that will clearly and most adversely affect that class of customers (domestic and rural consumers) to which it is by statute bound and required to give a preference. Further, the proposal cretes an admitted significant detrimental socio-economic impact on a segment (low income domestic consumers) of that preferred class. However, even in the light of this statutory preference and glaring admission, BPA completely refuses to describe and consider reasonable mitigating alternatives.

BPA states at page 109 the objectives it was attmpting to achieve in preparing its proposal as follows:

a. Revenue from rates must be adequate to recover costs;
b. While meeting the revenue requirements, the burdens should be distributed among the recipients of the service in a manner that is equitable;
c. Rates must be designed to encourage efficient use of electricity, while maintaining a close relationship between costs incurred and benefits received.

The objectives stated fail to recognize the preference given to domestic and rural users pursuant to 16 USC 832(c) (a), which provides:

"In order to insure that the facilities for the generation of electric energy at the Bonneville project shall be operated for the benefit of the general public, and particularly of domestic and rural consumers, the Administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives."

In analyzing and developing the rate structure proposed in this draft EIS, BPA has totally ignored the statutory purpose and mandate given to it by Congress. Further it has violated NEPA by totally refusing to look at any potential alternatives which would have a positive effect on a retail rate structure, mitigating the effect of its wholesale rate increase. BPA chose to ignore the existence of its statutory duty to serve and protect domestic and rural consumers.

The clearest and most actionable portion of the EIS is the attempt to avoid responsibility regarding the ultimate effect on domestic users. BPA attempts to avoid its legal duty to those it was created to serve by stating that the utilities themselves have the authority to control retail rates.

BPA clearly has a statutory authority pursuant to 16 USC 832(d)(a) to put stipulations and conditions in its contracts with utility customers concerning the resale and retail rates used. We suggest the following general alternative.

a. BPA would establish a two tier EC-8 rate.

b. The cost reduction given in the first tier would be passed on to the consumer by way of stipulation contained in the BPA contracts with the participating utilities.

c. Additional revenue requirements may be met by implementing various alternatives. These could include:

1. Combining second tier rates with an inverted rate structure;
2. Increasing the share-the-savings rate above 50 percent;
3. Increasing rates for nonpreference customers."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: The revised EIS considers baseline rates which could assist low income customers. Bonneville has also treated the subject of preference and priority to domestic and rural consumers in its final EIS.

Comment: "The draft EIS does not adequately take into account and describe the actual cumulative real rate increase which will be faced by the domestic end-use consumers in 1980. The ultimate consumers are going to be faced with a combination of the effects of the 90 percent wholesale rate increase along with the additional probable raises in rates necessitated by individual utilities themselves. Therefore, the magnitude to be faced by low income domestic users is going to be far greater than that described in the draft EIS. . .

If BPA had truly undertaken an interdisciplinary approach it could have easily produced the detail required. . .

BPA could and should have further instituted studies of its own using methodologies available."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: The Final EIS allows the ultimate consumer to determine the impact that BPA's proposed rate increase, and alternatives thereto, will have on him. Although the retail rate faced by a consumer cannot be predicted, BPA has included information which should help the ultimate consumer determine the overall increase he is apt to face. The publication "Typical Electric Bills" dated June 1, 1979, is included in order to give the retail customer a guide to the rate structure currently in effect for his utility. Although Bonneville did not expand its treatment of low income customers, per se, the analysis presented allows each customer, regardless of his income level, to determine the impact of BPA's rate increase increase on him.

Comment: "The August 1978 Draft EIS Report states that the proposed price increase will impact low income families in a major way and as a percentage of income their energy costs could be seven times that of persons making $25,000 or more.

Before imposing such a burden on society, BPA must examine, specify, and recommend rate structures to retail utilities which would build some economic equity with the system. it should be done to prevent the heaviest burden from falling on those who can least afford such increases. BPA comments that, "the most adverse impact of BPA's proposed rate increase would be its effect on family budgets." The report suggests that . . . "such impacts could be partially mitigated by increasing such programs as Federal Aid to Families with Dependent Children and Supplemental Security Income Programs," for example. I consider such increased expenditures from the Federal Treasury uncalled for and intolerable. By increasing such programs, we are continuing the individual dependence on the welfare system. In reality, we would be providing a subsidy to the utilities electrical generating system while poor people take the flack for the increased Federal welfare budget."

Joyce Cohen
Lake Oswego, Oregon

Response: While Bonneville can make recommendations to its utility customers regarding the rates under which they sell power, BPA is not legally permitted to take any coercive action against a utility unless their rates are discriminatory. Until retail utilities establish lifeline or baseline rates, it is likely that the poor will have to be assisted by Federal and state programs.

Comment: "Regarding the effect of the proposed rate increase on families which live on fixed incomes, the Grant, Lincoln and Adams County Conference of Governments noted that "considerable public funds have been spent providing "weatherization: services to single family houes together with emergency relief for those who are unable to pay their power bills. The proposed rate increase would not only hurt those who have not been helped in these ways, but would also return those who received this assistance to the condition of needing more emergency help."

Grant-Lincoln-Adams County
Conference Of Governments
Ephrata, Washington

Response: Bonneville acknowledges that its new rates will increase the need for expanded emphasis on programs which increase energy efficiency and that low income consumers may experience difficulty in meeting increased utility bills.

Comment: "The statement does not adequately address the alternative of a "baseline" rate structure. We note that BPA is "currently analyzing" such a rate structure. We believe that BPA should complete this analysis, make a recommendation and circulate a new draft that fully discusses this alternative.

We believe that if a rate structure was developed that separatly billed customers for the costs of the hydropower that they used and the thermal power costs that they have asked BPA to assume for them, much less confusion would result and it also encourage utilities and their customers to forestall such costly thermal power sources with cost-effective energy conservation, while retaining their "share" of the lower cost hydroelectric power.

As long as BPA underprices the cost of new load growth to its utility customers, confusion shall result and the goal of an energy efficient society shall elude us all."

Sierra Club
Seattle, Washington

Response: Bonneville has included an expanded section on baseline rates in its revised EIS. In addition, BPA's baseline paper is available for public review.

While a baseline rate might be useful in reducing power costs to a particular customer class, BPA's General Counsel has determined, from a review of the legislative histories of the various Federal project authorizations that Congress has always contemplated that BPA would develop a systemwide melded rate. Furthermore, with respect to differentiated hydro and thermal rates, Congress was told and its committee reports reflect that hydro and thermal resources would be sold under a melded rate. An example of this continuing understanding is the following exchange from the report of the House Subcommittee on Public Works, 91st Cong. 2d Sess, Public works for Water, Pollution Control and Power Development (1970) at 866-867 (refering to power from net-billed thermal plants):

Mr. Whitten. Is it true that the power purchased under these contracts will actually be sold at a loss as far as the cost of that particular generation is concerned?

Mr. Richmond. I think technically that is true. We do really what any privately and publicly-owned system does, which is to look at our total generation cost and set our rates so that we can recover our total costs with different plants producing at different cost levels. The thermal plants in this case will be higher cost producers than any of the others. The thing in terms of setting rates and meeting our payout requirements and so on is: what are our total production costs as compared to our total payout obligations?

Mr. Whitten. The high cost here will be worked in with your current costs and you in turn will come out with an average rate that you will use across-the-board?

Mr. Richmond. That is correct.

BPA's General Counsel has concluded that: "separate rates for hydro projects and thermal projects without Congressional approval, would be a breach of faith with the Congress, and in my opinion, contrary to the ratesetting sections of the Bonneville Project Act, the Federal Columbia River Transmission System Act, and the repayment requirements of the Grand Coulee Third Powerhouse Authorization Act (P.L. 89-448)." Opinion of the General Counsel, Bonneville Power Administration, March 12, 1979.

While marginal cost pricing of themal power may have a conservation impact, unless the customer's total monthly bill with a baseline rate and a thermal rate were higher than with a melded rate for a given amount of power the conservation impact is not all that clear. Bonneville has incorporated some marginal cost signals in its rates by altering the relationship of capacity and energy charges to reflect the results of the marginal cost study which shows energy costs increasing much faster than capacity costs.

Effects on Business and Industry

Comment: "The report (EIS) states that the effect on most industries should not be significant since elctric purchases for most industries account for only one to three percent of value added.

All industries except the family budget can pass the increased costs through as a "cost of doing business."

Joyce Cohen
Lake Oswego, Oregon

Response: The Final EIS acknowledges that the residential customer does not have the option of passing increased power costs on to others (Chapter V, Section B.1.d.)

Comment: "The Lighting Department feels that if availability credits to the direct-service industries are to be considered, the basis for the calculation of these credits and documentation must be made available for review. We, therefore, strongly recommend that

Bonneville prepare this documentation, and in the process of doing it, Bonneville should review the opportunity cost of alternatives to marketing the interruptable power that constitutes the reserve. It has been suggested by some entities that the direct service industry contribution to regional reserves is being overstated. We do not know if this is correct but we certainly believe that it is a concern that should be addressed."

Seattle City Light
Seattle, Washington

Response: Bonneville engaged a consultant (Foster Associates Incorporated) to examine the value of the industrial reserves. The consultant was charged with developing a proposed method which could be used to evaluate separately the capacity, energy and transmission resources provided by the industries. Although this study is not complete, initial results suggest that such an evaluation include the considerations of risk (the probability that the reserves will be needed) and alternative costs (the costs of avoiding the use of the reserves). The proposed availability credit determination includes limited estimates of both of these considerations and therfore is a limited estimate of the value of reserves.

Comment: "The direct-service industries shown in Table 17 (which include aluminum, magnesium, titanium, zirconium, nickel, mining, and iron and steel) are shown with proposed rate increases which range from 113 percent to 123 percent. Other than a rather general statement to the effect that this may ultimately affect their production output and consequently change their employment level, little attention is paid to the impact on the economy of the Northwest, or to the impact on the mineral posture of the United States of such increases. It would appear that some analysis of these issues is necessary."

U.S. Department of the Interior
Washington, D.C.

Response: See Chapter V, Section C.1.

Comment: "At this point, the almost hysterical, dire, detrimental effects of increased rates the DSIs are predicting, particularly the aluminum companies, should be addressed, which even in the low water year of 1977, the worst year in the history of BPA, amounted to the abnormally high percentage of 36 percent of the total BPA power sales in 1977, compared to 29.3 percent in 1976, when the rate per kWh for the aluminum companies was 3.15 mills compared to 2.22 mills per kWh in 1977, or a rate reduction of 29.52 percent. (Reference 1977 BPA annual report and CY 1977 generation and sales statistics charts). What better proof need there be to substantiate the fact that the aluminum industry in the Pacific Northwest is being subsidized to an intolerable degree by all the other ratepaters in the Columbia River Drainage, whether served as BPA preference customers' ratepayers or ratepayers of the investor-owned utilities, such as Idaho Power Co. or Utah Power Co."

Idaho Consumer Affairs, Inc.
Nampa, Idaho

Response: If the DSIs receive their full contract demand, the rate they pay is exactly the same as that paid by utility customers. However, because DSIs operate 24 hours a day, they are able to take their power at an extremely high load factor, thus lowering their average cost per kWh. In addition, if Bonneville restricts the DSIs, i.e., cuts off some of the power they would like to have, the industries are compensated. Bonneville benefits from the right to restrict the industries and as a result, BPA can lower its rates to all its customers.

Comment: "The dire prediction of mass lay-offs of aluminum company workers and loss of business due to reversed multiplier effect of purchasing power on the region's economy, if extremely low rates for electrical power used by the aluminum companies is not still made available to them when their most favored class rate schedules studies made by independent sources, not financed by the aluminum companies themselves. The worst case assumptions (EIS-BPA rate increase proposals - page 73)(Northwest Energy Policy Project-Executive Summary-Final Report - page 27) are that the regions' employment would be reduced by only one percent by 1985, (when most of the DSI contracts will have expired) for the five most power, intensive industries in the Northwest. In the best-case scenario (same references) the impact on these five industries and the region's economy would be negligible. Even the worst-case scenario would take 26 years to have a 90 percent locational effect. Also the reduction in the Boeing Company's plant production after World War II didn't have a long term adverse affect on the Puget Sound's economy."

Idaho Consumer Affairs, Inc.
Nampa, Idaho

Response: Bonneville's assessment of impact on the direct-service industries includes reference to the independent studies mentioned above (see Chapter IV, Section B.2.c.) and does not attempt to portray a dire picture regarding the effect of rate increases on the aluminum industry.

Comment: "Perhaps BPA believes much too strongly the propaganda that the aluminum companies have such a beneficial economic multiplier effect to the economy of the Columbia River drainage basin, which as been disseminated principally by the aluminum companies, and even to a considerable effect by BPA itself. In case BPA has succumbed to this propaganda, they should put more credance into some of their own as well as information pomulgated by the Pacific Northwest Regional

Commission, (PNRC). For example, the PNRC, executive summary page 25, "Five industries --(1) Food processing, (2) paper, (3) primary metals (principally aluminum), (4) stone, clay and glass, and (5) chemicals; listed in the order of their employment importance--currently employing about 5 to 6 percent of total workers in the Northwest, are the most important energy-intensive enterprises in the region and the most likely to be impacted by higher energy prices. Therefore, it can be seen that the adverse impacts of higher rates will affect more people in the food processing and the paper industries, expecially when the closely related lumber industry and other forest products industries are included, and even this EIS, itself, page 25 shows that only 17.6 percent, 492,800 of the 2,800,000 employed persons in 1975 (page 24) are engaged in manufacturing, and only 5.6 percent of those employed in manufacturing are employed in the manufacture of primary metals, 12,000 in aluminum.

From the above, it can be readily determined that the extremely low rates for power to the DSI's proposed by BPA can cause very serious adverse economic impacts on the food processing industry, not to mention irrigation rates to some farmers who might be comtemplating pump irrigation for their present rill systems, to save water, not to mention some acreage contemplated being put under pump irrigation in the future.

In addition, the serious adverse economic effects to the paper and allied forest products industries from such low DSI rates, to those not present BPA-DSI customers, should be considered, more fully, by BPA.

Also, labor substituted for energy, possible should be considered by BPA, instead of their dwelling on the subject, to grant undue rate relief to the energy intensive industries, who in turn could obtain some or more of their energy requirements from the investor-owned utilities, or even the DSIs could begin making arrangements to provide some of their own, at least, generating facilities. Here cogeneration is a promising possibility in the Columbia River drainage basin."

Idaho Consumer Affairs, Inc.
Nampa, Idaho

Response: Bonneville has attempted to provide accurate information regarding the impact of power rate increases on its direct-service customers as well as other industrial customers. Bonneville is also engaged in sponsoring a major study of the potential for industrial cogeneration in the Northwest.

Effects on Irrigation Farming and Food Prices

Comment: "It would be helpful . . . to discuss the social impacts of higher irrigation rates. Agriculture is a significant part of the economy of the Pacific Northwest. Changes in electrical rates for irrigation affect not only farmers, but also food processors, other related industries, and the general population."

U.S. Department of the Interior
Washington, D.C.

Response: The social impacts of higher irrigation rates have been addressed in the Final EIS (see Chapter V, Section B.3.C.).

Comment: "The section on irrigation repayment assistance "tends to confuse the reader. It states that no funds will be needed for irrigation assistance before 1997, but implies that the 1979 rate could be lowered by 1.5 percent if irrigation assistance were not required. In any case, we question the validity of the 1.5 percent after reviewing the "Repayment Study for Fiscal Year 1977" as reported in BPA's Fiscal Year 1977 Financial and Statistical Summary. According to the study, BPA's O&M expenses, one component of the estimated total revenue, will remain constant from 1998 until 2050, the last year of the study. We believe this is an unrealistic assumption, as BPA's O&M costs and other costs are likely to increase due to inflation. By holding O&M costs constant, BPA has in effect overstated the percentage of revenues that will be needed for irrigation assistance. Also, if irrigation projects scheduled for construction in future years do not proceed as planned, less irrigation assistance will be required than carried in BPA's studies."

U.S. Department of the Interior
Washington, D.C.

Response: The purpose of the repayment study is to determine the revenue required by Bonneville to meet its obligations. Inflation is considered for the effective period of the rates. To assume any inflation rate beyond the rate period would artificially raise the revenue requirement. Revised estimates of the irrigation assistance impact show it to be slightly less than one percent. Of course, if projects are not built and inflation continues, the ultimate effect will be even less than that.

Comment: "Very large amounts of government money have been and are proposed to be spent on irrigation projects for this area. The large volumes of energy needed to operate modern irrigation systems means it will no longer be feasible to conduct irrigation on lands which would be only marginally usable for production in the present economy.

Both of these problems have implications for demands on public funds. Both of these issues relate to the economic health of this region. Finally, both of these points affect the quality of living in the area served by the Conference."

Grant-Lincoln-Adams County
Conference of Governments
Ephrata, Washington

Response: Bonneville conducted a study which analyzed the effect of various price increases on the amount of land under cultivation. A short-run increase of 100 percent in retail electricity prices was projected to lower irrigated acreage by less than one percent. In the long run such an increase would bring about approximately a 4 percent reduction in land which is currently being irrigated. A 200 percent retail increase would be expected to result in a loss of about 8 percent of irrigated land while a 400 percent increase in retail electricity prices would cause almost 29 percent of the land to be taken out of production. It is true that large increases in retail electricity prices would reduce the amount of irrigated land and would have an impact not only on the individuals directly affected, but also on the Pacific Northwest economy as a whole. However, of the alternatives discussed in this statement, only the marginal cost alternative would necessitate retail electricity price increases in excess of 100 percent. The analysis of the impact of various price levels on irrigators is presented in Chapter V, Section B.3.

Comment: "We object to irrigation information used in the Environmental Impact Statement which was totally removed from the BPA service area."

Harney Electric Cooperative, Inc.
Burns, Oregon

Response: This information has been largely deleted and replaced with a section which quantifies the impact of BPA's rate increase on irrigators (see Chapter V, Section B.3).

Comment: "At several points in the statement the effects on irrigation of an increase in power rates are mentioned. One alternative for farmers who have converted from gravity to sprinkler would be to return to gravity irrigation as the cost of energy surpasses the labor savings gained from sprinkler. A discussion of this possibility in the statement would be useful."

U.S. Department of the Interior
Washington, D.C.

Response: Although the costs and benefits of a return to a gravity system from a sprinkler system are not discussed per se, Table V-11 does show the relative use of energy by three types of irrigation systems: center pivot, sideroll and gravity. A farmer interested in converting back to a gravity system might use this information to assist him in determinig if he should change systems.

Comment: "Washington irrigated lands have proven to be some of the most productive areas in our country. This is primarily due to progressive and aggressive cultural practices, good soil types, long growing season and abundant available water. We are not alone, there are many areas of production. We find our general location is a curse. Our transportation costs are higher to every major market in the United States. The only thing that has kept our competitive balance with these other areas has been our power expenditures. Without readily available and reasonably priced power our competitive marketing structure will fly out the window.

An energy advantage and the highest of quality standards on our products are the only factor that have kept us in a balanced competitive situation.

We have not had an increase in price for our products for three years. Many commodities have watched a steady decline during that time. This year alone our production costs increased 29 percent (most of which are tax increases) and next years projected costs and estimated income look about the same. Increase in taxes and production costs with a stagnant return. . . . The BPA impact statement referring to agriculture states that this rate increase would afect 1 to 1½ percent of present agricultural product in the area. The impact would be much greater than that. We cannot pass our costs along and it would throw our competitive marketing into a real tailspin."

Ralph L. Thomsen
Pasco, Washington

Response: Bonneville acknowledges the lessening of Northwest farmers' competitive advantage in its Final Environmental Impact Statement (Chapter V, Section B.3).

Comment: "On Friday August 25, the Bonneville Power Administration's Proposed Wholesale Power Rate Increase to become effective December 20, 1979, was published in the Congressional Record. The proposed rate structure is significantly different from the present one and results in a severe economic hardship to summer peaking systems serving irrigation type loads. While the average increase for all Preference Agencies is 92 percent, Northwest Irrigation Utilities' projected increases are in the range of 100 to 120 percent with over a 140 percent increase during the summer months."

Northwest Irrigation Utilities
Richland, Washington

Response: Bonneville recognizes the problems that Pacific Northwest farmers face. In response to comments BPA reconsidered its wholesale power rate, proposing to include a seasonal energy differential. In addition, the EIS now includes a section for quantifying the impact of a BPA rate increase on the irrigator.

Comment: "The section on irrigation impacts tends to oversimplify the irrigation impacts with the result that the negative impacts are overstated:

We note the comment in the second paragraph, section 4 on page 97 which states that, 'water use by irrigators will decrease with an increase in electricity rates, both from increased water application efficiency and from a decrease in irrigated acres.' We seriously question the latter point. Considering the general increasing world need for food and fiber and urban encroachment on agricultural land (which will generally take land in other areas out of production) it appears to us that insufficient data is available to support the decrease irrigated acres' statement. In addition, while river depletions reduce streamflow, pumping from wells increases streamflow. In areas where most of the reduction is in acres irrigated from deep wells, the final statement should indicate stream flows could actually decrease.

The statement is made in the third paragraph that water pollution resulting from irrigation would be reduced 2-3 percent with a rate increase. We doubt that the 2-3 percent figure is statistically significant, especially considering the fact that it is based on 'rough calculations'. The message of the paragraph, that irrigation contributes to water pollution, is not always true. Several factors contribute to water pollution, including dissolved solids, as well as suspended solids. Irrigation return flows are often higher in dissolved solids, but lower in suspended solids. The final statement should state that whether such water is more or less polluted would depend on local conditions.

We recommend that the forth paragraph be changed to indicate that while irrigated acres, per se, reduce emissions of fugitive dust by increasing the moisture content of the soil, the total amount of fugitive dust from farming entering the atmosphere depends upon the total acreage farmed by all methods, including dry farming."

U.S. Department of the Interior
Washington, D.C.

Response: The section on the impacts of irrigation on the physical environment has been rewritten to reflect these comments.

Comment: "The EIS should address the effects of increased electric costs for agricultural production on the export of farm products to oversea markets and the balance of trade."

State of Oregon, Intergovernmental
Relations Division
Salem, Oregon

Response: The Pacific Northwest Regional Commission is funding the Northwest Agricultural Development Project which is studying this very question. Unquestionably, the U.S. will lose some of its competitive advantage if the price of production is not rising in other parts of the world.

Comment: "HEC full-well realizes that there is a world-wide energy shortage and that this nation and the world must conserve energy, but it would be penny-wise and pound-foolish to conserve energy at the expense of forcing agricultural land out of production. HEC notes that vast amounts of fertile farmlands are being taken out of production daily for subdivisions, highways, and various other types of construction. The remaining farmland must be made more productive and incentives be given to the nation's farmers to make a fair profit or we will have world-wide food shortages and food will be available only at exorbitant prices. Today's marginal farmlands must feed the world tomorrow. The BPA has an obligation to recognize this fact.

31 million acres of farmland have been swallowed by developments in the past decade. The Environmental Protection Agency issued a directive to help slow this trend (copy of newspaper clipping attached), but now BPA states the proposed wholesale rate increase will put still more farmland out of production.

A congressional study showed that 13.4 billion more dollars were paid for electricity and natural gas in 1977 than in 1976; BPA's proposed rate increases these charges futher.

The Environmental Impact Statement has dwelt at length on the effects of increases in cost to irrigation in Nebraska, Missouri, and Texas and it would appear that this has weighed heavily on the decisions of this proposed rate. We feel BPA has not studied in depth the results the rate increase would have on Pacific Northwest agriculture. We further believe that BPA should expand, in depth, their rate study and its effect on agriculture within the Northwest. This study should also take into consideration, costs of transporting produce to markets as the distance to these markets is much more extensive than most other areas in this nation.

In conclusion, we feel the proposed BPA wholesale increase is inequitable as it is inflationary to the economy of this nation at a time when the President is requesting voluntary restraints on price increases.

We feel this nation must continue to encourage agricultural production at its maximum as this is one of the major export items which we must have to balance the trade deficit.

We feel that to much fertile land is being removed from production without the added loss from high energy costs or force-out by high energy costs. We do not feel BPA has the authority to alter the Congressional acts which state irrigation is to be one of the benefits of the Multi-Purpose Dams. We encourage a reduced summer energy rate and if that is not possible, then we feel the BOR irrigation assistance aid should be abolished as this is a required BPA expense. (590 million plus further BOR projects.)

We object to BPA's proposal to collect O&M expenses in advance on any generation plant.

We object to fuel costs being added to months when fuel is not being expended.

BPA acknowledged the Bonneville Project Act, as well as its intent, of the multipurpose use of the dams on the Columbia River System until 1974 when BPA succeeded in pulling an end-around play by abolishing the irrigation credit and substituting a seasonal rate. The 1974 proposed wholesale rate had originally attempted to increase summer usage two to one over winter usage. (BPA is again attempting to pull off the same sneak play.) However, in 1974 BPA relented and set a maximum increase which granted a certain amount of relief to the summer rate. The BPA wholesale rate increase in 1974 had the same effect as the BPA proposed rate increase will have in 1979. HEC would have one of the highest increases of all distribution utilities due to heavy summer irrigation usage.

BPA's proposed rate increase penalizes the nation's food producers with no economic justification on the part of BPA because the irrigation season is at a time when BPA enjoys a surplus of hydroelectric power; a time when expensive thermal power is not needed. BPA's proposal will force the marginal food producers out of business and will increase the cost of doing business for the food producers who are able to survive. This can only add to the problem of double-digit inflation which is the number one economic problem of the nation today.

Conservation must be practiced by use of methods that prevent waste and add to the efficiency of the nation. Increasing the cost of an aluminum can will only add to the cost of beer and soda pop; the home owner can insulate his home as well as drop the temperature a degree or two, but he must be able to afford food for his children. This nation, which includes BPA, must get its priorities in proper perspective.

The BPA rate, as proposed, is in complete reverse to everything logical. Those utilities with the lower 90 to 100 percent increases serve primarily wintertime peak loads, consisting of residences and apartment houses, at a time when hydrogeneration is at its minimum, will have a 110 to 140 percent increase in rates. We cannot see the logic in BPA's proposal. The equality in penalizing the summer peaking systems and giving special benefits to the winter peaking systems at a time when winter peaks are the critical condition is beyond our comprehension."

Harney Electric Cooperative, Inc.
Burns, Oregon

Response: Bonneville's revised wholesale power rate proposal includes a seasonal differential which will help mitigate the impact of the rate increase on irrigators. Bonneville is concerned about the effect of its rates on irrigated land and engaged Norman K. Whittlesey of Washington State University to study the matter. His findings are published in the report "Demand Response to Increasing Electricity Prices by Pacific Northwest Irrigated Agriculture."

Effects on Bonneville's Preference Customers

Comment: "One reason why BPA cannot predict how a utility will react to the rate increase is the fact that the preference agencies have a direct responsibility to the public. The District's Commissioners must be responsible to their constituencies' desires and shape rates to further those goals."

Clark County PUD
Vancouver, Washington

Response: While Bonneville cannot predict how a utility will react to a rate increase, it is possible to give the public an idea of what the impact would be if the utility were to pass the increase along to its customers on a uniform basis. Thus, the EIS quantifies the impacts of a uniform rate increase.

Comment: "In at least one case we believe the economic information presented to be misleading. On page 52, it is stated that the 1980 costs for Seattle would be 4.03 percent higher with the 90 percent BPA rate increase than without it. Although the total rate increase would amount to 90 percent, the effective increase for Seattle City Light would be 137 percent."

Seattle City Light
Seattle, Washington

Response: Bonneville has deleted the reference to Seattle City Light in the Final EIS.

Comment: "PPC suggests that BPA include figures showing the maximum and minimum of the range within which wholesale utility purchaser's total costs will be affected by the proposed rate increase, giving three typical examples."

Public Power Council
Vancouver, Washington

Response: In the Final EIS, BPA has avoided mentioning percentage increases. Such figures are often misleading as utilities with low average power costs will tend to show a high percentage increase even though the millage rate under the new rates may still be lower than it is for other utilities.

Comment: "Central Lincoln People's Utility District takes exception to the Bonneville Power Administration's method and results of the proposed 1979 Wholesale Rate Increase impact on the ultimate consumer of a utility. We believe the results to be incorrect and troublesome for the many preference customers of BPA whose ratail electric rates must be increased to cover the wholesale power rate increase.

On pages 50, 51 and 52 of the Draft Environmental Impact Statement for the Proposed 1979 Wholesale Rate Increase, the Bonneville Power Administration has developed considerable discussion as the proposed rate increase on utility costs.

BPA's method simply divides utility costs into two parts - power cost and non-power costs. To determine utility impacts, BPA escalates non-power costs at an annual rate of eight percent between 1976 and 1980. Power costs are held level until 1980, the proposed increase is added as a lump sum. Realism dictates that power cost as a cost of doing business increases each year with annual power load increases. Even with the same wholesale power rates, the dollars for power costs increase with sales. For example, BPA received a seven percent increase in revenues from preference customers in 1977 as compared to 1976.

The impact on utility revenue requirements coming from power sales as a result of an increase in power costs can be more closely approximated by using the relationship of power cost to operating revenues. If a utility has power costs which take 40 percent of its revenues and then, experiences a 90 percent increase to its power cost expenses, the same number of dollars will be required from an increase in revenues. That number is equal to 90 percent of 40 percent of a 36 percent retail increase.

BPA's choice of 37.32 percent as being the average relationship of power costs to total expenditures is not typical or average. This relationship for rural electric cooperatives is 33 percent; municipal utilities 43 percent and public/people's utility districts 41 percent.

The District recognizes the BPA impact statement probably should discuss the impact of the proposed wholesale rate increase on its customers. However, to adequately cover such impacts as proposed in the draft EIS, BPA should completely analyze each customer's financial statement. Even then, utility planning and capital investment programs would not be included because of BPA's lack of knowledge on these matters for the 1980 test year.

If discussion is necessary, BPA should limit itself to strictly a wholesale rate increase to be experienced by the customer. Further discussion as to a percentage increase to be passed through by a preference customer to the ultimate consumer would be misleading because of faulty and erroneous evaluation."

Central Lincoln People's
Utility District
Newport, Oregon

Response: Power costs for each revenue alternative are based on 1980 loads, not 1977 loads. Bonneville feels that it is inappropriate to assume that the existing ratio of power costs to total costs will necessarily remain constant. Table V-3 shows, for each revenue alternative, the ratio that would exist for each utility in 1980 if nonpower costs were to increase by 7.15 percent per year (overall average increase for preference customrs between 1974 and 1977) and if load forecasts were accurate. Clearly the marginal cost alternative would differ significantly from the no-action case. The discussion of the impacts on the ultimate consumer in Chapter V is based on the typical bill for each utility as of June 1, 1979. This information is almost up-to-date and should enable the reader to gain a better understanding of likely impacts on him, which is one of the purposes for writing an EIS.

Effects on California

Comment: "The objective (of equitably distributing the revenue burden among the recipients of a service) is violated by the fact that with the proposed rate increase the Regional utilities are asked to pay only 50 to 70 percent more for surplus energy, while California utilities are asked to pay up to 400 percent more, for the same surplus energy. Clearly California consumers are required to bear a far greater burden than those in the Region. The higher rate to the California customer is particularly inequitable in view of the fact that the regional customers have first call on any surplus. The California customers only get what is left over. Similarly, with respect to BPA's third objective, no reasonable analysis can support the proposition that setting rates to California at excessively high levels while setting rates to Regional customers artificially low encourages conservation or 'discourages wasteful use' in the Northwest. Moreover, since the California consumers basically purchase dump hydro energy which would otherwise be spilled over the dams, such sales should be encouraged. "

Pacific Gas and Electric Company
San Francisco, California

Response: The secondary energy rate proposal has been revised and the standards be applied to the Southwest would be the same as those for Northwest utilities, with the exception that Northwest utilities would still be given purchase preference. Such regional preference in purchasing surplus power is mandated by Sections 3 and 5 of P.L. 88-552 (78 Stat. 756, 16 U.S.C. S837). The higher cost for secondary energy would discourage consumption by customers of utilities purchasing secondary energy from Bonneville. However, the energy conserved would be that which would have been generated by the utilities' highest cost generation resources and there is no reason to believe BPA would be placed in the position of having to spill water. The proposed H-6 rate is designed so that it would always be to the benefit of BPA's customers to purchase secondary energy when it is available to displace higher cost generation sources.

Decreases in consumption by customers of utilities puchasing BPA's secondary energy may be offset by increases in consumption by customers of utilities benefiting from the application of H-6 revenues to Bonneville's firm power capacity costs. The net effect of the rate on consumption should be insignificant.

Comment: "PG and E does not contest BPA's need for increased revenues; however, we are strongly opposed to the rates BPA proposes for sales to customer located outside the Pacific Northwest Region (Region). Those rates are discriminatory, and place an unjustified and excessive burden on the electric power consumers in California.

The rates proposed by BPA, applicable to sales to PG and E, Schedules F-7 and H-6, abandon the cost of service principle and, instead, adopt a formula based essentially on what the market will bear. This change will likely cause the price to the California consumer to drastically increase from the present 3 mill range to something near 15 mills, an increase of nearly 400 percent! By comparison, the proposed rates applicable to BPA customers who are fortunate enough to be located wihin the Region, are based on cost. Indeed, such rates are below cost to the extent that they are subsidized by the profits gained from the sales to out-of-Region customers. This discrimination is unconscionable and without justification.

Further, the interests of conservation are not served by a rate scheme, such as the one BPA proposes, which encourages overuse in the Region by rates that are made artificially low by subsidies received from sales outside the region.

The discrimination against the California customers of BPA is apparent on the face of the BPA rate proposal. The rates proposed by BPA would increase the rates applicable to California customers between 240 and 400 percent. By comparison, the rates applicable to customers located in the Region would be increased only 50 to 70 percent for the same 'surplus' power."

Pacific Gas and Electric Company
San Francisco, California

Comment: "Energy which cannot be used or stored for later use in the Northwest is made available to consumers outside that region. Under the proposed rates, Burbank consumers of such exported surplus energy may be changed up to 250 percent of that being charged to the Northwest purchasers. What is the basis for proposing this inequity? By using costly oil fueled generation which the surplus Northwest energy would displace as a basis for the proposed rate, these inequitable charges take on the characteristic of an onerous burden on our consumers. Burbank's rates include an Energy Cost Adjustment Charge (ECAC). Changes in fuel and purchased energy costs are passed through to our consumers by monthly adjustments of the ECAC. Must the explanation of increases in the ECAC to our consumers include the statement that for every cent per kilowatt hour increase resulting from increases in prices of foreign oil, they are also required to pay an additional o.5¢ per kilowatt hour for energy received from Federal hydroelectric plants in the Pacific Northwest? We can provide no justification for such a concept. We believe that charges to all consumers of Federal hydroelectric energy should be based on the appropriate cost-of-service for that energy. We believe that California consumers of nonfirm power should not be charged $50 million in excess of costs to help offset off-peak demand costs which the Northwest consumer of firm power will not be required to pay."

Public Service Department,
City of Burbank
Burbank, California

Responses: The H-6 rate proposal has been modified since the August 1978 initial proposal to reflect some of the comments that were received. However, the rate proposal continues to be based on share-the-savings principles. While some sales may be made at rates as high as 20 mills per kilowatthour, BPA estimates that most sales will be made at the rate floor and that the average sale would be made at about 8 mills per kilowatthour. A thorough discussion of the statutory authority and economic basis for the proposed share-the-savings rate and past use of such a rate concept by BPA and other power marketing administrators is contained in a document entitled Staff Evaluation of the Official Record dated July 1979). While BPA is of the opinion that it has a legal basis for a rate which is different for one group of customers compared with other groups, the latest proposal contains a share-the-savings rate which applies in both the Northwest and the Southwest.

Comment: "'Energy Supply' is discussed very briefly in Paragraph 3, Subchapter A, Chatper II, which refers to 'BPA Role EIS, Part 1, Chapter V or Energy Incorporated, 1977', for a more complete discussion. Table V-46, Summary of Loads and Resources, in the BPA Role EIS shows that imports of energy are included in BPA's resources. One of the sources of imported power that BPA should consider is power available from power plants owned by the California Department of Water Resources (DWR).

DWR's Hyatt and Termalito Power Plants have pumpback capabilities with peaking capacity of about 900 MW and an annual average generation of 2.3 billion kWh. DWR's contract with three California electric utilities for the sale of Hyatt and Thermalito power will terminate on March 31, 1983. After March 31, 1983 some of this power will be used for operating the pumps of the California Aqueduct. On April 1, 1983, about 500 MW of peaking capacity will be available at Hyatt and Terhmalito which could be sold or exchanged for off-peak energy. Since DWR has 300 MW of EHV transmission capacity available for transmission of power to or from the Northwest, BPA should consider the possiblity of purchasing power from DWR or exchanging off-peak energy for peaking capacity. DWR may also have excess power available from its other generating sources when the California Aqueduct is shut down or partially shut down and during adverse water years when the shortage of water whould reduce water project pumping requirements. Therefore, there may be times when power sale or exchanges between the DWR and the BPA system are beneficial."

Resources Agency of California
Sacramento, California

Response: Bonneville would, of course, be pleased to consider sale or exchange agreements which would be to the mutual benefit of BPA and the California Department of Water Resources. However, these exchanges would not affect the estimates of revenues from sales during the period that the proposed rates would be in effect.

Comment: "Socioeconomic impacts for California are mentioned (in the summary page at the beginning of the Draft EIS) but . . . no physical impacts were mentioned for California."

Clark County PUD
Vancouver, Washington

Response: The proposed rates are not expected to create significant impacts on the physical environment in California since they are not anticipated to affect the extent to which BPA's secondary energy is used to displace thermal generation. It would be counterproductive for Bonneville to increase its nonfirm energy rate to a level which would impact sales to California since such sales are made only when no market for the energy exists in the Northwest. Bonneville would be forced to spill this energy and lose any potential revenues associated with its sale.

Comment: "BPA's $90 million difference in cost (between the existing and proposed secondary energy rates) at $15,000 per (job) represents 6,000 jobs lost to California. The aggregate increase in electricity prices quoted at 2 to 4 percent higher includes very large utilities such as PG&E, Edison, San Diego, and L.A. which masks a relative increase that is much higher for us. For example, if the surplus brought in for 1974 or 1975 had been priced at 15 mills, this would have resulted in an estimated overall increase in the cost of energy for Glendale of 24 percent for the former year or 8 percent for the latter.

If this price structure goes into effect, without doubt there will follow even greater price increases by other supliers of non-firm energy. This could provide more overall energy availability for

Glendale as the price crosses over the IOU coal and nuclear plant output costs, but this is not an easily estimated crossover point, and in any case can only add to inflation of energy prices."

City of Glendale
Glendale, California

Response: The revised H-6 rate is expected to generate approximately $50 million more in revenue than the existing nonfirm energy rate. It is not possible to accurately estimate the portion of this amount which would be associated with purchases made by Southwest utilities.

Glendale's estimate of cost impacts of the proposed H-6 rate on their system has been incorporated into Section C.4. of Chapter VI.

Comment: "The Impact Statement does not deal with the one year rate review vs. five year rate review question. The Federal Register does, showing an 8 mill on peak and 6 mill off peak price with .4 mill intertie surcharge (what is the justification for this surcharge concept?) and a maximum of 24 mills/kWh. This brings up another problem. The BPA annual report indicates a 90 percent overall rate increase in 1978 with 1981 promising a 20 percent additional increase. This 20 percent increase will raise the 4.5 and 6 mill figures to 5.4 and 7.2 mills, which is only 11 percent behind the people "safely" locked in for five years at 6 and 8 mills. The years following 1981 will surely hold more than 11 percent in increases which will put us above the five year rates. This action seems inconsistent with the arguments presented to us which convinced us that we should accept the one year review principle.

These actions and the apparent lack of support on the part of BPA for municipal preference which has been a part of past policy and legislation are difficult to understand and have considerable bearing on our operation. We have for a long time viewed the intertie operation as a partnership between agencies to their mutual benefit. We strongly feel that the original concepts of the D.C. Intertie and PNW surplus should remain bananced against realistic costs of hydro generation."

City of Glendale
Glendale, California

Response: Since the initial proposal of August 1978, Bonneville has negotiated to revise contract provisions that permit rate adjustments on December 20, 1979, July 1, 1981, and each July 1 thereafter. The amended contracts are in contrast with the power sales contracts that began in 1939 that permitted rate adjustments only at 5-year intervals. All of BPA's customers now have 1-year rate review power sales contracts. Therefore, the revised proposal that appeared in the Federal Register on July 16, 1979 did not include rate schedules designed to cover a five-year period as originally proposed.

The purpose of the Pacific Northwest (PNW) - Pacific Southwest (PSW) Intertie charge is to recover the costs of the PNW-PSW Intertie as determined in the Federal Columbia Power System Cost-of-Service Analysis. For the revised study of July 1979, the transmission system was divided into seven segments including the PNW-PSW Intertie. This differs from the initial study where only three segments were identified inlcuding the PNW-PSW Intertie. The Intertie segment includes the cost of the PNW-PSW Intertie as authorized by Congress. These costs are allocated among intertie services, included both power sales and wheeling, by the 12CP method.

Comment: "To justify BPA's use of 'share the savings', the use of 'share the savings' rates by the Federal Southeastern and Southwestern Power Administrations is mentioned, but the presence or absence of geographical discrimination in their applications of 'share the savings' was not discussed. The geographical discrimination is the most novel portion of BPA's use of this rate design principle and the portion with the least legal and historical justification. (Section 2 of CEC Staff comments on rate increase.)

Several potential alternate forms of a 'share the savings' concept for secondary energy rates is necessary. In particular the application of a rate in two tiers for spilled hydro and hydro that would have displaced Northwest thermal energy should be discussed. A provision to make Northwest thermal displacement for economic reasons are unacceptable use of H-6 energy unless inter-tie lines are fully loaded should be discussed. Finally, the environmental and energy benefits of rates which encourage additional oil displacement through additional shipments of Northwest energy to California should be included."

California Energy Commission
Sacramento, California

Response: The proposed H-6 rate has been revised to apply equally to sales in the Southwest and Northwest. A provision barring the use of H-6 energy for thermal displacement in the Northwest unless intertie lines are fully loaded would violate the regional preference requirement under which Bonneville must operate. The Northwest Regional Preference Act, Public Law 88-552, limits the sale of hydrogenerated energy to the Southwest to that which is surplus to the needs of the Pacific Northwest. Nonfirm energy distribution priorities are as follows: (1) firm energy loads will be served if any are not being met, (2) new reservoirs will be filled, or depleted reservoirs will be restored by serving customer loads with non-firm energy, and (3) generation from customer's thermal plants will be displaced with non-firm energy.

The displaced generation from the thermal plants may later become available for sale to other utilities or industries, including sales to the Southwest. After all markets for non-firm energy in the Northwest have been satisfied, non-firm energy which would otherwise be spilled under current practices in the Northwest, is marketed to the Southwest, thus displacing oil-fired generation. Preference customers in the Southwest have preference rights on Federal energy exported to the Southwest, but have no preference rights over utilities in the Northwest, preference or otherwise.

Comment: "BPA's analysis with regard to share-the-savings arbitrarily sets the price of excess power sold at 50 percent of the difference between the cost of production and the cost of the purchasers to produce it with alternative sources. The difference between the cost of power being sold by BPA and the cost of alternative sources by purchasers would be approximately between 24 and 27 mills per kilowatt hours. The share-the-savings rate chosen has been used primarily by utilities whose costs are very close, within a few mills. This is not the case that this region finds itself in. Therefore, this alternative should be reviewed with regard to selling BPA's secondary power on a share-the-savings rate, for example, at least 80 percent of the difference."

People's Organization for
Washington Energy Resources
Olympia, Washington

Response: The formula for calculating the price of nonfirm energy has been modified in the latest proposal. The intent of the rate is to equitably share the savings between utilities in the Northwest and utilities in the Southwest. If 80 percent of the savings were derived by BPA, preference utilities in the Northwest would receive most of the benefit.

Comment: "The draft EIS notes that public meetings were held in the Northwest in June and November, 1978. Since the proposed rate increase and its alternatives have major socioeconomic and environmental impacts on California and implications for national energy and air quality policies, at least some hearings should have been held in California to assure coordination with all interested parties. To partially remedy this error, some of the Economic Regulatory Administration hearings and hearings for the development of a final EIS on the rate increases should be held in California. This will allow a more adequate development of the record."

California Energy Commission
Sacramento, California

Response: Members of BPA's staff met with about 40 persons representing utilities in California on November 16, 1978, regarding Bonneville's proposed rates. The meeting was held at the request of several of Bonneville's H-6 customers. Meeting participants were invited to submit written comments to Bonneville.

Comment: "The estimate of 10 billion kWh in average transactions between BPA and California does not agree with the 10.9 to 12.1 billion kWh figures in table 19 of the cost-of-service study for Fiscal Years 1978 to 1983. Socioeconomic impacts are underestimated by this error. See page 89 of Draft EIS."

California Energy Commission
Sacramento, California

Response: Bonneville acknowledges this discrepancy. The cost-of-service study made available at the time of the issuance of the Draft EIS indicated 1980 secondary sales of 11,668 megawatthours. Bonneville's cost-of-service study has undergone some revision since August, 1978, and a revised figure of 10,600 megawatthours is being used in the Final EIS for nonfirm energy sales.

Comment: "The socioeconomic impacts of the rate increase were also under estimated by the exclusion of transactions involving California and Northwest utilities other than BPA. Other rates for secondary energy could be expected to rise as an indirect effect of BPA's rate increase, but this effect was not considered."

California Energy Commission
Sacramento, California

Response: It is reasonable to assume that the rates for secondary energy applicable to transactions involving California and Northwest utilities other than BPA may be influenced by the presence of the proposed H-6 share-the-savings rate. Whether or not the rates the Northwest utilities will charge can not be answered at this time. The variables involved are not included in Bonneville's econometric model, preventing any quantification of the probable impacts resulting from changes in the rate charged in these transactions.

Comment: "The discussion of socioeconomic impacts resulting only from the portion of the rate increase which is above the Northwest rate of 6 mills/kWh is confusing to the reader. The socio-economic impacts of the full rate increase should be spelled out."

California Energy Commission
Sacramento, California

Response: The Final EIS incorporates this recommendation in Chapter V, Section A.2.

Comment: "Data on, or at least a qualitative discussion of, the differential impacts upon California utilities due to differences in their contracts with BPA for capacity or the extent of their reliance on Northwest surplus energy should be included in this section. Some California municipal utilities' rates could rise by 20 percent."

California Energy Commission
Sacramento, California

Response: This recommendation has been incorporated in Section C.4. of Chapter VI.

Comment: "The revenue increase to BPA resulting from a rate of 15 mills/kWh, using sales data from the cost-of-service study, averages \$146 million per year. Additional revenue required to repay costs is \$32.7 million annually, leaving a surplus of revenue over costs of \$113 million. This \$113 million surplus does not correspond to the \$49.6 million surplus from California sources projected in the Wholesale Power Rate Design Study. The \$49.6 million surplus (\$82.3 million rate increase) corresponds to an average rate of 9.7 mills/kWh. BPA's EIS analysis should conform to the rate increases proposed in its rate design study."

California Energy Commission
Sacramento, California

Response: The H-6 rate in the draft EIS permits the rate of nonfirm energy to vary over a defined range therefore making it difficult to predict what actual average costs will be. The 15 mill figure was selected as a worst case estimate for the Draft EIS to avoid underestimating the impact of the proposed H-6 rate. The final EIS discusses the entire range of values which could result under the proposed rate (See Chapter V, Section A.2).

Comment: "An alternative to the use of all of the \$49.6 million surplus generated in California for the reduction in Northwest rates, which would use revenue for acceleration of environmental and engineering studies and new intertie construction should be presented. A conservative estimate of 12-14 billion kWh in additional secondary energy annually could be available to the Pacific Southwest under average water conditions, with large regional environmental and great national economic benefits. Failure to set aside revenue from California revenues for these studies would have major environmental and economic impacts if intertie construction is delayed for lack of planning funds. Given appropriate BPA rate policies to encourage the export of surplus energy, construction of additional intertie capacity would provide economic benefits to the Northwest and California, and should be a national priority given the potential for reducing oil imports by 25 million barrels annually."

California Energy Commission
Sacramento, California

Comment: "The consideration of the impacts on California are too narrow in that they only consider the impact of increased rates for existing energy deliveries. BPA's policy of using surplus hydro power to reduce thermal output in the Northwest is enunciated in the Wholesale Power Rate Design Study and the cost-of-service study. This rate policy has resulted in the failure to produce and deliver 2½ to 4 billion kWh of power annually in 1975, 1976, and 1978, using intertie lines. The annual impacts of the failure to deliver this energy include national economic losses of $45 to $75 million, the unnecessary importation of 4 to 7 million barrels of oil, and the production of an extra 7 to 11 million pounds of oxides of nitrogen, much of that in Southern California. These adverse impacts should be clearly laid out in the section of the impacts of rate design on California, and the impacts of alternatives to the proposed BPA rates and policies should be evaluated and compared to those of the rate proposed by BPA."

California Energy Commission
Sacramento, California

Responses: Bonneville examined the claim that its policy for sales of non-firm energy resulted in the failure to annually produce two and a half to four billion kilowatthours in years 1975, 1976, and 1978 and concluded that the impacts mentioned above did not need to be addressed in the Final EIS. The results of Bonneville's analysis are printed in the Staff Evaluation of Official Record dated July 1979. BPA concluded that the availability of additional Northwest thermal was considerably less than the annual figures of two and a half to four billion kilowatthours. Bonneville's analysis which was based primarily on Trojan and Centralia thermal plants shows that only approximately 1.7 billion kilowatthours could have been produced over the four year period from 1975 to 1978 and this did not consider intertie capacity. On many of the dates when additional output could have been available there was little or no available intertie capacity.

Bonneville is currently studying the value of building another intertie to California and, in general, monitors its transmissiion system to be sure that lines are built when needed. As a result, there is no need to set aside the revenues from non-firm sales to California to study the feasability of building another intertie.

Effects on Consumption/Conservation

Comment: "Conservation Rates. It is not stated if baseline rate tests are to be applied to individual end-use consumers or to the utility's total load. Any test applied to total load is discreminatory toward utilities that are growing. Growth in consumption cannot categorically be assumed to be bad or undersireable. As the population continues to increase, the total energy consumption is likely to continue to increase."

Clark County PUD
Vancouver, Washington

Response: Bonneville agrees that determining baseline allotments as a percentage of a utility's existing load could be discriminatory. Allocation of baseline power on a per customer basis could avoid such a problem.

Comment: "The woefully inadequate efforts by BPA to insist on a more adequate scrap aluminum recovery and recycling program by the aluminum companies as an absolute pre-requisite for them (aluminum companies) to become eligible for even a melded rate, is intolerable, and we feel BPA should be severely condemmed, at least criticized, for not demanding, insisting, or even strongly recommending more effort by the aluminum companies be made. With the exception of the Reynolds Aluminum Company, and we have been closely observing this situation, we have seen or heard of <u>no</u> concentrated effort by any other aluminum company to launch a meaningfull scrap drive and recycling effort. . .

Should the scrap recycling program be resisted by the aluminum companies not now conducting one, BPA should then propose an inverted rate structure be adopted for the electricity these recalcitrant aluminum companies use, starting with a 75 percent rate, averaged, then in effect and being charged by the Tennesse Valley Authority, which in Fiscal Year 1977 was approximatley 16 mills. Thus, it is proposed that the rate for non-compliance for recycling program would be 12 mills for the first billion kilowatthours used, 14 mills for the second billion kilowatt hours used and 16 mills for all kilowatthours used over 3 billion kWh peryear used, on a plant by plant basis.

Considering the fact, the United States is having acute balance of payment problems, requiring the aluminum companies to institute a meaningful recycling program is imperative and good public policy."

Idaho Consumer Affairs, Inc.
Nampa, Idaho

Response: Bonneville believes that the comment has validity although implementation of such a rate would violate the rate-making principles of simplicity of rate design, ease of understanding and ease of administration. Such a rate could, however, become more viable as the Northwest energy supplies shrink.

Comment: "Page 122 (of the draft EIS) states that, 'load forecasts and generation requirements are not expected to change as a result of BPA's rate increase' and in the same paragraph that 'generation requirements will be lower with the BPA rate increase than would be the case if no increase wer implemented'."

Seattle City Light
Seattle, Washington

Response: Because load forecasts and generation requirements are based on an anticipated rate increase of approximately 90 percent, there will be no change in expected load as a result of the rate increase. However, if no increase were adopted, Bonneville would expect consumption to increase above the forecast level.

Comment: "It (EIS) fails to substantively examine specific rate alternatives that are designed to encourage and reward conservation actions by individual utilities and direct service industries."

Seattle City Light
Seattle, Washington

Response: Additional material on these topics has been included in the Final EIS (see Chapter VI, Section C.9.).

Comment: "Specific pricing systems should be adopted for industry which would encourage conservation by industrial customers."

Joyce Cohen
Lake Oswego, Oregon

Response: See Chapter VI, Section C.9.

Comment: "It (the Draft EIS) does not provide either site or region-specific information on the environmental impacts of the proposed rate increase. Although this type of information may be difficult to produce for an action such as this, whose primary effects are entirely economic, consideration of the secondary specifically environmental impacts must not be neglected. We recommend that correction of this omission be approached from the perspective of the regionwide effects the proposed rate increase and its alternatives would have on demand for electricity, since ultimately, the electricity demands of BPA's customers will determine how many new power plants will be required to serve this region."

City of Seattle
Seattle, Washington

Response: The suggested approach has been used in Chapter IV of the Final EIS where BPA examines the effects of the proposed revenue increase and alternatives thereto on the regional demand for electricity, fuel oil and natural gas. In addition the environmental impacts of each of these alternative, are presented in Table IV-3 and IV-4.

Comment: "The impact (of BPA's proposal) should be large energy reduction or curtailment but not savings. Savings implies that the unused energy is stored or available for future use."

Clark County PUD
Vancouver, Washington

Response: It is anticipated that the effects of the BPA proposal would be on output from power plants using nonrenewable resources such as gas, coal and oil. Hence, these "saved" resources would be available for future use.

Comment: "No consideration is given in the report to reduction of use by Commercial Customers. The State of Oregon will institute in the near future, a new Commercial Building Code, expected to produce considerable energy savings in the future."

Joyce Cohen
Lake Oswego, Oregon

Response: The response of commercial customers to various price levels is discussed in Chapter IV of the Final EIS.

Comment: "Institution of 'Conservation Rates' by utilities should be requested by BPA along with any sharp rate increase such as the 90 percent increase proposal."

Joyce Cohen
Lake Oswego, Oregon

Response: Bonneville supports the goal of efficient use of energy and is in the process of exploring a variety of methods for achieving that goal. Both wholesale and retail rate structures are being examined with respect to their conservation potential.

Comment: "Increased conservation would change the timing of needed new generation but not reduce the amount. (Total amount not amount per customer or per person.)"

Clark County PUD
Vancouver, Washington

Response: This assumes that population and energy dependence will increase indefinitely. Even so, conservation can reduce the amount of generation required at a given time.

Comment: "It is stated that the higher the price of energy, the more consumers will save. What do you mean? Will consumers curtail use or convert to other energy sources instead? Do you mean that when the price for energy is higher relative to other consumer needs, the more consumers will reduce their use of that energy?"

Clark County PUD
Vancouver, Washington

Response: The questions are addressed in Section B., Chapter IV.

Comment: "What consideration was given to expansion of conservation programs and alternatives before commitments were made to the Hydro-Thermal Power Program? Experts agree that energy saved by conservation is cheaper by far (one-sixth to one-third) than energy generated by building new generating plants."

Joyce Cohen
Lake Oswego, Oregon

Response: Conservation programs and alternatives were not considered in the initial development of the Hydro-Thermal Power Program (HTPP). The cost effectiveness (both political and economic) of conservation has increased dramatically since the planning of Phase One of the HTPP. Conservation programs are expected to be given full consideration by Bonneville in its efforts to accommodate future power requirements.

Comment: "A major issue in conservation policy is how to reward customers for efforts in reducing electrical consumption. A paradox exists in that while some individuals may make efforts to conserve, the benefits (i.e., lower average costs) are often enjoyed by all customers. The EIS concentrates its analysis of alternative rate structures on the potential application of Average Cost Pricing and Marginal Cost Pricing methodologies, both of which apply rates equally within rate categories, irrespective of individual efforts to reduce consumption. A potential consequence is that an individual would not be completely rewarded for pursuing conservation policies. The EIS mentions a 'Conservation Rates' methodology which does give consideration to conservation actions, but this is apparently not seriously considered within this rate proposal."

Seattle City Light
Seattle, Washington

Response: These issues are discussed in Chapter VI, Section C.7.

Comment: "The range of alternative rate increases is narrowly circumscribed around the figure of 90 percent based on continuation of existing BPA policies. However, the EIS states that BPA is currently considering a conservation policy, the form of which could conceivably considerably alter the growth of electrical demand, and consequently affect the amount of rate increase necessary to meet BPA statutory requirements. While the EIS does cite several studies which indicate that conservation activities may not radically affect the magnitude of revenue needs, we would nevertheless recommend more consideration of the effects of actual conservation policy alternatives in the rates analysis."

Seattle City Light
Seattle, Washington

Response: Typically the effects of conservation programs require substantial time periods to reach their full potential. It is unlikely that conservation measures under consideration by BPA could have a significant effect on the need for BPA's currently proposed rate increase. Furthermore, Bonneville's conservation program is not yet sufficiently developed to permit reasonable speculation on the extent of its impact on power requirements.

Comment: "A conservation incentive factor should be built into the rates. Customers whose usage does not increase above a set percentage should be charged a lower rate than users who increase at that percentage. Users whose increase exceeds the set percentage should be charged a larger rate. This would put costs of new facilities on the new users."

Steven B. Rubin
Seattle, Washington

Response: Bonneville does not believe that customers whose service areas are growing should be penalized for growth over which they have no control. Of course, BPA may be able to encourage conservation through its rates (probably using a methodology similar to that described in the baseline section), but such rates would be likely to be based on a per customer basis rather than on a utility's total load growth.

Comment: "As mentioned in the EIS, pursuing conservation activities may result in excess BPA power resources. Several alternative policies for disposal of excess energy are discussed under 'mitigation', but not in the detail necessary to quantify the significant consequences on revenues and costs. This should be explored to a greater degree, in the context of actual impacts on rates."

Seattle City Light
Seattle, Washington

Response: Bonneville does not expect to have a large surplus of available power even if conservation were to be practiced. In addition, should such a surplus develop, BPA could market it first to Northwest utilities and then to the Pacific Southwest under the H-6 nonfirm power rate.

Comment: "Large efforts should be made to encourage less dependance on BPA electricity."

Steven B. Rubin
Seattle, Washington

Response: Bonneville has established a Conservation Section in the Branch of Power Resources and is implementing a number of pilot programs related to conservation.

Mitigation

Comment: "With respect to the time differentiated daily and seasonal demand charges, PPC and BPA both recognize that some customers will be impacted more severely than other customers by BPA's rate design shift. PPC suggests that BPA try to mitigate the impacts of its rate design changes. BPA should consider phasing in rate design changes in order to reduce the impacts of an abrupt change. Such phasing in is at least a partial substitute for consistency and stability. However, if there are siginficant daily or seasonal variations in cost these variations should be reflected in the rate structure."

Public Power Council
Vancouver, Washington

Response: While continuity of rate design is an important criterion in rate development, continuity of rate level is perhaps even more important. As a result, BPA and its customers signed contract agreements enabling BPA to change rates, if necessary, every year starting July 1, 1981. While the range of increases for BPA's utility customers in 1980 ranged from 72.2 percent to 108.7 percent based on the July 1979 revised proposal, it should be noted that the utilities with the largest percentage increases still have lower average rates than most of these with smaller percentage increases. In fact, the millage increases are often almost identical. The millage increase spread is 2.32 to 3.61 mills, with over 90 percent of the customers averaging between 2.89 and 3.40 mills.

Comment: "Bonneville's proposed 90 percent rate increase as it impacts the poor shocked me to no end. Even more shocking than the percentage of increase was the mitigating measures assigned under Chapter VI, Section A., paragraph three.

It has been a pretty well established fact that the Consumer Price Index as it relates to the SSI cost of living raises are never near the true rate of inflation in the real world.

May I suggest that your office ask the DOE to disregard paragraph three of such nonsense, and of such Chapter and Section.

The EIS is incomplete in as much as no consideration has been given to the fact that the over all inflation impact-stress has not been studied and defined in regards the SSI recipient and the world that creates that total inflation impact-stress mandated by Title XVI of the Social Security Act of 1935, and its amendments.

To regard the DOE-EIS as a complete statement of impact would be to disregard the rights of the nation's most defenseless peoples to a life of dignity, decency and health."

Wayne D. Stamps
East Wenatchee, Washington

Response: Bonneville is concerned about the impact of its rate increase on low income consumers. As a result, BPA studied, in some detail, baseline rates. While impact-stress, per se, was not studied, impacts on customer expenditures were examined. Although SSI payments probably do not keep pace with inflation, they are periodically increased to help maintain the recipient's purchasing power. Bonneville believes the paragraph, as written, is accurate.

Comment: "It is felt that BPA should more strongly advance the practicality of BPA's being allowed to set aside a reasonable portion of their revenue each year, possibly one half mill, for the purpose of building low-head hydro projects, and upgrading presently constructed hydro projects, even building medium-head hydro projects, which along with low-head hydro projects, could be built at many locations which are environmentally acceptable to the majority of Columbia Basin residents, and the country in general. In addition, it is suggested that these projects could be amortized over a period of possibly 100 years, since a number of well constructed hydro projects are still generating power which have been on line nearly 100 years now; the beneficial results of the hydro program will be to mitigate the steadily rising costs of thermal electrical generation."

Idaho Consumer Affairs, Inc.
Nampa, Idaho

Response: Bonneville is under several constraints which do not allow BPA to set aside monies to build low-head hydro plants. First, BPA is a marketing agency and does not construct any generation facilities. Second, BPA is required by law to set its rates at the lowest possible level. While such a construction program might be attractive, it is not feasible under the legislation under which BPA operates. Bonneville did consider a revenue alternative in which the average depreciation life of generation facilities was extended to 85 years. Congressional approval would be required prior to adoption of this change, however. See the section entitled "Reduced Revenue Level, for further discussion of the change in amortization policy.

Comment: "Individual BPA customers should have the responsibility of apportioning and subsidizing electricity costs their users must pay. This should not be concern of BPA."

Steven B. Rubin
Seattle, Washington

Response: Bonneville is required by Section 5a of the Bonneville Project Act (50 Stat. 734.5, as amended by 59 Stat. 546, 16 u.s.c. 832 d (a)) to ensure that contracts entered into with its customers for the sale of power "contain such terms and conditions, including among other things, stipulations concerning resale and resale rates by any such utility, as the administrator may deem necessary, desirable or appropriate to effectuate the purposes of this Act and to insure that resale by such utility to the ultimate consumer shall be at rates which are reasonable and nondiscriminatory." BPA's utility customers are also required by the Act to file their schedules of rates and charges with Bonneville. Based on that authority, Bonneville engages in a review of its utility customer's rates. In addition, BPA is concerned about the impact of Bonneville's own rates and the utility's rates on the ultimate consumer. Unless BPA were to adopt a baseline rate, the utility customers would have the responsibility of apportioning and subsidizing electricity costs their users must pay. Bonneville does not now have authority to implement baseline rates.

Transformation Charge

Comment: "Transformation Charge. The preference agencies are fairly well split on this item. Here again this confusion resulted from the 1974 rate design and is another argument for BPA to return to its former method of not discounting delivery voltages. Perhaps BPA can make some provisions to compensate those who have in the last five years planned on the discount to amortize investments."

Public Power Council
Vancouver, Washington

Response: Bonneville's customer service policy has traditionally limited multiple delivery points for any particular customer. As customers become larger and require additional delivery points, Bonneville and the customer determine the most economcial service based on a "one utility concept." Then a "feasibility test" determines Bonneville's participation. It is the opinion of the BPA General Counsel that, absent other reasons, "equity considerations" alone are not sufficient to provide legal justification for an expenditure from the Bonneville Power Administration fund. Those customers that believe that BPA would derive a benefit from acquisition of a customer's transformation facilities may petition the Administrator to acquire, lease, or lease-purchase such facilities.

Comment: "On the question of the transformation (or facilities) charge, we believe it should be retained. The proposed EC-8 rate is a complete reversal by BPA, with respect to the facilities charge as now existing in the EC-6 rate. This charge appears to be arbitrary and without merit.

The removal of the transformation charge we feel is unjustified and would unfairly penalize utilities who have built their own or purchased BPA facilities in the past. This rate proposal (EC-8) arbitrarily "roll-in" the customer transformation charges with the transmission portion of the demand charges. The results are a uniform transmission rate for all BPA wholesale customers whether or not they provide their own transformation. This results in utilities, such as Seattle and others, subsidizing utilities without their own transformation capabilities. This is hardly an equitable arrangement.

Providing subtransmission and distribution voltages to a utility is a service that can be separated from the transmission system and can be identified by BPA. These costs should have been identified in the Cost-of-Service Study. In the past, BPA did, in one manner or another, identify these costs. This is demonstrated in the fact that the EC-6 rate has a transformation charge and must have had some basis.

We have indications that a transformation charge is preferred (in a modified form of the EC-6) by many Northwest utilities which includes Seattle. The transformation charge however should recognize that the transmission voltage level is not uniform over the entire BPA service area. A utility therefore should not be assessed a transformation charge if it has built its facilities to utilize the existing BPA transmisson grid.

With the above modifications made to a transformation charge, we find that a majority of utilities will support it."

Central Lincoln People's
Utility District
Newport, Oregon

Comment: "BPA instituted the transformation charge in 1974 only to propose its elimination five years later. Such rate design swings can have a substantial adverse affect on a utility's operation. The PPC believes BPA should continue the transformation charge. However, we feel the application of the charge should be modified. An information poll of its members conducted by PPA indicated that approximately 75 percent favored retaining the charge. PPC is willing to have its subcommittee meet with BPA to discuss the details of the information poll.

We believe that the transformation charge is applicable for two basic reasons. First, many utilities have made long range financial commitments based on the transformation charge continuing to exist. Second, it is inappropriate to charge all utilities for costs associated with a specific service such as transformation."

Public Power Council
Vancouver, Washington

Responses: The transformation charge alternatives are discussed in Chapter VI, Section C.5. of the Final EIS.

Comment: "Page 112 <u>First complete paragraph</u>: Transformation charges should be discounted from the proposed capacity rates."

Clark County PUD
Vancouver, Washington

Response: Transformation charge alternatives are discussed in Chapter VI, Section C.5.

Comment: "We object to the inclusion of the transformation charge in the demand component of schedule EC-8. We objected to the transformation charge when first instituted in 1974 because the structure of the charge did not acknowledge the various services that are required by Bonneville's customers. We feel that the transformation charge should have at least one more step in the rate sturcture to acknowledge a lower supply level, say 34.5 KV or 7.2/12.5KV.

As a result of Bonneville's past service capability at 69 KV, this District was required to construct 138 miles of transmission line at the 69 KV level, as well as some 20 substations also at the 69 KV level. The consturction of the 698 KV transformation within this District is a direct consequence of Bonneville's initial capability of service to this District. Subsequent changes in Bonneville's level of service could not be followed within the District because of the capital plant supported by consumers served at the 69 KV level.

We, in the past, have had the opportunity to compare this District's requirement of building facilities at a 69 KV voltage level with that of other utilities where Bonneville has provided the necessary transmission and trnasformation at a 7.2/12.5 KV level. Our protest in 1974 concerning the transformation charge fell on deaf ears as Mr. Durocher and Mr. Goldwater, at customer service meetings, expressed the importance and provided a multiude of reasons why such a rate structure was necessary. At one customer service meeting in Seattle, we were advised that it would be economically feasible to purchase Bonneville facilities utilizing the transformation charge for amortization of the capital cost. Now, suddenly in 1979, we are confronted with an entirely different philosophy whereby the transformation charge is conveniently tuched into the demand charge and wielded indiscriminately against all customers. As a consequence of the transformation charge established in 1974, several utilities did purchase Bonneville facilities utilizing the transformation charge as the financial factor in the purchase.

While at first acknowledging a transformation charge, Bonneville is now saying, in effect, "We have changed our minds". But in what position does this place the preference customer and what credibility does Bonneville gain from this about face? If rate philosophies can be manipulated in such a fashion, what can we expect in the future? Additionally, I have been unable to identify any section on the environmental impact statement which addresses the transformation charge, nor any section devoted to the effect or the impact on preference customer utilities by incorporating the transformation charge within the demand charge. We would appreciate reassurance that the transformation charge manipulation, indeed, was addressed in the EIS and that those impacts were identified."

Challam County PUD
Port Angeles, Washington

Response: The Final EIS addresses the subject of the transformation charge in Chapter VI, Section C.5. Along with a discussion of the reasoning behind the chage in policy is an analysis of the associated impacts.

Miscellaneous

Comment: "Furthermore, this time the region's consumers have apparently no alternative but to pay these additional cost, whether justified or not. To avoid this situation in the future the WEC feels that BPA should more aggressively exercise its oversight role to ensure that facilities in which it has financial liability are constructed and operated in a cost-effective manner. We strongly recommend that in the final verion of this EIS, BPA spell out specifically what it intends to do to minimize future rate increases, particularly as regards the net-billed facilities.

To summarize then, the Washington Environmental Council feels that in is final version of its Wholesale Rate Increase EIS, BPA should:

1. Provide a more detailed explanation of the causes of this rate increase and what it intends to do to minimize future increases; and,

2. Extablish some mechanism which encourages conservation measures which are judged to be cost effective on a region wide basis and which is tied directly to its rates."

Washington Environmental Council
Seattle, Washington

Response: The revised EIS provides more detailed information concerning the causes of the approximately 90 percent rate increase (see Figure III-7). Bonneville commissioned the firm Theodore Barry Associates to examine the management practices of WPPSS. In addition, BPA's Administrator is taking a more active role in the oversight of WPPSS' activities. Bonneville has included time-of-day pricing in the proposed rates (which should result in a reduced peak demand for BPA's system). Other conservation measures are being studied by BPA's conservation section in the Branch of Power Resources.

Comment: "Page 40 Average Cost Rates. BPA must use carefully the "consideration to value of service" in its rate concepts. As BPA preference customers are electric utilities, they cannot choose between electrical and other energy sources.

The last two sentences remain unclear and might be restated or deleted."

Clark County PUD
Vancouver, Washington

Response: This section has been deleted.

Comment: "Page 112 b.(3). The EC-9 rate implies that BPA can supply new customers. As the District has been notified that BPA is insufficient in 1983-84, why is item (3) included when BPA cannot serve new customers?"

Clark County PUD
Vancouver, Washington

Response: Some of our contract provisions do state that for certain violations of some of the provisions of the contract, the Administrator has the option of terminating the contract. Bonneville has not exercised this option. The Administrator might, in fact, under certain situations declare the contract invalid, but continue to serve and apply this rate.

This rate, or its predecessor for supply of load growth reserves, was instituted in 1974. It is an anticipatory rate, looking to the time when we would not have customers on a requirements contract basis. During this period BPA may be carrying a reserve for the preference customers as a group, or reserve for unforseen load growth, that might be made available to supply requirements in excess of the BPA obligation.

Comment: "Should BPA pay thermal-nuclear bond subsidies during construction, these monies should be reduced by whatever benefit plant owners obtain from such subsidies.

Load factors from thermal power plants (nuclear) whould be considered at 55 percent not the 75 percent shown in the draft EIS. Track records for current nuclear plants show the lower figure to be more accurate and representative.

The concept of internalizing external costs (P. 36) is necessary and desireable."

Steven B. Rubin
Seattle, Washington

Response: The 75 percent figure used in the EIS is for all new thermal generation whether coal or nuclear.

Comment: "Summary #4, fourth paragraph, last sentence. If, indeed, the Federal System hydro peaking capability will be increased, how it will be increased needs to be explained. In paragraph three of #4, you cite the reduced tailwater fluctuations, then you cite the increased peaking capability. Will you do this while decreasing the tailwater fluctuation?"

Clark County PUD
Vancouver, Washington

Response: Bonneville expects to have increased peaking capability in the future. For example, the second powerhouse at Bonneville Dam should add 272 megawatts of capacity to the hydro system. Such increased peaking capability will probably cause increased tailwater fluctuations.

Comment: "The practice of cross-referencing material in the EIS with sections of the "Role EIS" is questionable, as, we understand, the "Role EIS" is currently under revision."

Sierra Club
Seattle, Washington

Response: In most cases references to the Role EIS have been deleted. However, on a few occasions it remained necessary to reference the Role EIS in order to give the reader adequate supporting material for the issue being discussed.

Comment: "Page 112 Second complete paragraph. Will at-site power purchases be made available to preference agencies or is it technically a "frozen" rate?"

Clark County PUD
Vancouver, Washington

Response: At-site power is no longer available to any customes who are not already receiving power under this rate.

Comment: "Page 66 Figure 16. Another graph is needed to show the magnitude of each class of customer use to compare to the composite graph (Figure 16). With only the composite graph, it distorts the relationship of the residential load to the other loads."

Clark County PUD
Vancouver, Washington

Response: This comment is well taken, but the source did not include a second graph.

Comment: "Page 7 Footnote 1. What customer has not signed the rate review amendment?"

Clark County PUD
Vancouver, Washington

Response: At this time all customers have signed the amendment.

Comment: "Page XIV Table A. "Generation: column should be called 'Future Generation'."

Clark County PUD
Vancouver, Washington

Response: The correction has been made.

Comment: "Page 7 #4, second paragraph, last sentence. Another important impact that is mitigated by more frequent increases is the impact on consumers' ability to meet the mentioned 200 percent increase in BPA rates."

Clark County PUD
Vancouver, Washington

Response: The information has been added to the text.

Comment: "Page 1 A. Introduction 1. Third paragraph, last sentence. Is BPA suggesting that tne net-billing contracts should be breached?"

Clark County PUD
Vancouver, Washington

Response: BPA is not proposing that the contracts be breached, but Bonneville did support a contract amendment to the WPPSS agreements which would have reduced BPA's rate increase. See Chapter III, Section B for futher discussion of this topic.

Comment: "As nearly as possible, we suggest a BPA pricing policy that recovers the costs of energy sold to each consumer, discourages premature investment in energy facilities, reduces the relative financial burdens, among each class of customers for those using little energy, and makes the use of scarce resources more efficient."

Idaho Consumer Affairs, Inc.
Nampa, Idaho

Response: The Final EIS addresses each of these concerns.

Comment: "Impacts of the rate increase are probably predicated on a continuing high rate of inflation in the economy. One alternative scenario that might well be discussed is a downturn in the economy induced by restriction of the money supply or through wage and price controls. In the event this happens, some of the impacts might be quite different."

U.S. Department of Interior
Washington, D.C.

Response: The short-run impacts of the proposal are based on the economy as it now stands. Since most of the impacts are figured on an individual basis, rather than for the economy as a whole, the state of the economy is not relevant.

The long-run impacts are based on the PNUCC load forecast. Although alternative forecasts could have been used, it was felt that the PNUCC forecast reflected the utility's best estimate of future loads. Consideration of additional forecasts would simply have obscured the analysis by adding many more numbers while not shedding much additional light on expected impacts.

Comment: "The proposal adds to the inflation cycle in contravention of Presidential Directive. The predicted resultant increases in consumption of fuel oil and natural gas are likewise opposite of national interests. Options which would result in fulfillment of Bonneville Power Administration's statutory directive to encourage use at the lowest possible rates are discussed but evidently are not being proposed as part of the 90 percent increase package."

State of Oregon
Intergovernmental Relations
Divison
Salem, Oregon

Response: Bonneville's financial obligations are such that BPA is bound to seek a 90 percent revenue increase. It might be noted, however, that had all the participants in the WPPSS plants agreed to the subordinates financing proposal, Bonneville would have been able to restrict its increase to approximately 30 percent. Since BPA has had no increase in its wholesale power rates since 1974, the subordinate financing increase would have represented a 5.4 percent increase per year as compared with the 13.7 percent increase that must be adopted if BPA is to avoid defaulting on its financial obligations. The increases in fuel oil and natural gas which are reported in the Impact Statement are estimates which do not take into account dramatic changes in the price of these fuels vis-a-vis electricity. These increases are, of course, a concern to Bonneville, but are not something over which BPA has direct control.

Comment: "4. There is no evidence of an integrated analysis of the cumulative environmental and economic impacts of the proposed rate increase or any real alternatives to it."

Seattle City Light
Seattle, Washington

Response: The revised EIS estimates the environmental impacts of various revenue alternatives in Chapter IV. Economic impacts are discussed for each customer class in Chapter V.