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Final Environmental Impact Statement

THE ROLE OF THE BONNEVILLE POWER ADMINISTRATION IN THE PACIFIC NORTHWEST POWER SUPPLY SYSTEM

Including Its Participation In A Hydro-Thermal Power Program

U.S. Department of Energy

December 1980

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Final Environmental Impact Statement

THE ROLE OF THE BONNEVILLE POWER ADMINISTRATION IN THE PACIFIC NORTHWEST POWER SUPPLY SYSTEM

Including Its Participation In A Hydro-Thermal Power Program

Responsible Official

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Washington, D.C. 20545

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FOREWORD

This environmental impact statement (EIS) has been prepared pursuant to the National Environmental Policy Act (NEPA) of 1969 and is designed to assist the U.S. Department of Energy, and its component, the Bonneville Power Administration (BPA), with respect to the electric power planning process in the Pacific Northwest region.

The EIS was prepared before the enactment of the Pacific Northwest Power Planning and Conservation Act (P.L. 96-501) on December 5, 1980. The new Act provides for a regional electric power planning Council made up of representatives from the four Pacific Northwest States, who will develop a plan for supplying the electric power needs of the region. The Act also gives BPA broad new authority to undertake the responsibility within the region to supply the residential loads of investor-owned utilities, to continue to serve the existing direct-service industries, and to meet the future power supply needs of all utilities; and to fulfill these undertakings through extensive conservation measures and the acquisition of electric power from existing and new generating facilities.

This EIS is being released now to satisfy the Department's responsibilities in connection with NRDC v. Hodel, 435 F. Supp. 590 (D. Ore. 1977). It is not intended to satisfy the Department's NEPA responsibilities with regard to implementing the new Act. In this latter regard, the Act is being analyzed to determine NEPA responsibilities, and required environmental documents will be prepared as appropriate.

The EIS examines a range of alternative roles for BPA in influencing the future regional power supply. It is noteworthy that BPA's expanded role pursuant to the new Act is similar to that described in the EIS as Alternative 3. The EIS furnishes the contextual framework for the exercise of BPA's role by addressing the environmental impacts of the existing and developing regional power supply system and a range of future alternative system scenarios.

DEPARTMENT OF ENERGY
(DOE/EIS 0066)
FINAL ENVIRONMENTAL STATEMENT

The Role of the Bonneville Power Administration In the Pacific Northwest Power Supply System: Including Its Participation In a Hydro-Thermal Power Program

Prepared By
Bonneville Power Administration
Department of Energy
(December 1980)

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Abstract

This statement evaluates the environmental impacts associated with the operation and development of the regional power system under various levels of regional cooperation and coordination. This analysis examines the impacts of these varying institutional arrangements upon the operation of the existing/committed regional system, as well as their generic effect upon the future development of a coordinated regional power planning process. Also a "worst-case" analysis of future power resource development is presented. Included as part of this resource analysis is a series of scenarios which evaluate the impacts of nonthermal and thermal resource development. Those alternatives or institutional arrangements which advocate a formalized and comprehensive regional decisionmaking process are felt to be environmentally preferable in that they assure the consideration of nonpower interests and maximize the efficient use of the existing system.

PURPOSE AND NEED

Consistent with its mission to help assure a viable electric energy system in the Pacific Northwest, the Bonneville Power Administration (BPA) evaluates in this EIS, various BPA functions or roles in regional energy activities. BPA feels that a regional energy program would best serve the interests of the region by assuring that regional electrical needs would be met. However, such a regional program does not now exist, nor is it within BPA's present authority to implement one. Therefore, this EIS will study the definition and implementation of various BPA roles in the context of actions and reactions which may be taken by individual regional entities, such as utilities and State governments or groups of such entities. This evaluation will include BPA's participation in the Hydro-Thermal Power Program (HTPP), both historically and in the existing vestiges of that program.

BPA is not proposing, nor can it identify, and consequently does not evaluate, any existing discrete program to solve the projected energy shortage in the region. While the HTPP was designed to solve that problem, BPA's present authority does not permit such a program. BPA does propose to do what it can unilaterally in order to help relieve the energy shortage, through conservation for example, and whatever may be practicable or required under its existing authority in cooperating with other entities in the Pacific Northwest. This EIS examines the activities of the region which are subsequent to the HTPP, but these activities, even taken together, do not constitute a discrete or unified program but instead constitute the existing "program" only by being the sum of all the actions within the region. As a part of its regional analysis, BPA also evaluates, in alternatives 3 and 4, plans, which, if either were to be adopted by the Congress, would not only redefine BPA's role but would in addition provide the mechanism for the development of a regional program to solve the energy shortage.

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SUMMARY

Final Role EIS

<u>Status</u>: This EIS is a finalization of a Revised Draft EIS (RDEIS) filed with the Environmental Protection Agency (EPA) in April 1980 (DOE/EIS-0066). The revision was undertaken in response to comments received on the original draft and rapidly changing circumstances including the circulation of legislative proposals which, if enacted, would drastically alter the regional power planning process in the Pacific Northwest. The original draft EIS was filed with the President's Council on Environmental Quality (CEQ) in July 1977.

<u>Scope</u>: This programmatic environmental statement examines the impacts of the operation and development of the Pacific Northwest regional electric power supply system. This analysis includes an examination of the existing system and potential developments under alternative arrangements described in the proposal and alternatives.

The alternatives and the proposal are based upon differing levels of regional cooperation and coordination or alternative approaches to the one-utility concept, which is the main object of evaluation. Under this concept, the region's generation and transmission facilities are operated, as much as possible, as if they were under single ownership. The proposal and alternatives are designed to cover the range of institutional mechanisms for assuring a viable power supply system in the Pacific Northwest; they represent the range of alternative approaches to the one-utility concept. The alternatives range from minimal regional cooperation and coordination, through historical levels of cooperation in the Pacific Northwest, to a formal comprehensive approach to the one-utility concept. Correspondingly, the proposal and alternatives are also ordered to reflect increasing levels of BPA responsibility for the region's electric energy supply system.

In addressing the impacts of the regional power supply system, the alternatives examine the system as a whole. Accordingly, this analysis includes an examination of the impacts of the Federal Columbia River Power System, as well as non-Federal hydro and thermal facilities built to serve regional electrical firm loads, whether or not these facilities are located within BPA's geographical service area.

In addition to the institutional analysis this EIS includes an examination of the environmental impacts of future power system development. Because future energy resource mixes, i.e., the amount of energy to be contri- buted by each resource type, are not now known, a hypothetical or "worst-case" analysis was utilized. Following this approach, five resource scenarios were presented in the RDEIS for meeting regional electrical loads through 1998. These scenarios included two which were based upon development of renewable resources and conservation and three which were based upon conventional coal-fired and nuclear resources. In addition to these five, a sixth scenario summarizing the Natural Resource Defense Council's (NRDC's) Alternative

Scenario has been included in this final EIS. The NRDC submitted the Alternative Scenario as part of their comments on the RDEIS. The Alternative Scenario attempts to demonstrate that a regional power program relying on energy conservation and renewable resources is technically possible.

The actual resource types and mixes to be selected in the future are dependent upon a number of variables, including the outcome and application of existing and developing regional power planning processes, as well as technological developments which cannot be anticipated. As specific plans or proposals for power resource development are formulated, they in turn will be the subject of any necessary environmental assessments and EISs.

Proposal and Alternatives: Each of the alternatives and the proposal have been divided into two sections, one describing BPA's activities and the other giving an indication of complementary actions and reactions from the non-Federal sector of the regional power system.

The alternatives considered assign increasing levels of responsibility to BPA. Along this same continuum, alternative levels of regional cooperation and coordination (the one-utility concept) are examined, beginning with a minimal level under Alternative 1 and ending with a maximum level under Alternative 4.

No mitigation measures are identified outside those already included in the proposal and alternatives.

Alternative 1--Legislation Reducing BPA's Role in the Region. Under this alternative, BPA's existing authority, particularly with respect to transmission construction, would be significantly reduced through repeal of portions of the Federal Columbia River Transmission System Act (FCRTS) of 1974. Under such use restrictions, the Federal transmission system would not be available to facilitate regional planning involving non-Federal power. Except for Federal projects, BPA would have no responsibility to provide additions to the Federal transmission system. The regional structure depicted would resolve resource and transmission needs within the region through independent efforts by diverse utility interests.

Alternative 2--Existing Authority, Reduced BPA Role in the Region. Under this alternative, no new legislation, either reducing or expanding BPA's authority is considered, and no dynamic change from past practices is contemplated. For this reason this alternative is considered to be the "no action" alternative. Under this alternative, BPA would provide transmission and other services sufficient to deliver Federal power from Federal projects to preference customers. BPA would also offer to construct such other additions to the Federal transmission system as needed to integrate non-Federal generation. However, regional utilities and possibly other entities, such as State, regional, subregional, or local agencies, would form one or more "mutual operating agencies" which would construct and operate generating and transmission facilities, schedule the delivery of power generated by their plants, and provide other services which participants found economical to acquire through such an agency. To the extent that the mutual operating agency provided such services, BPA's level of activity in constructing transmission system facilities and additions would be reduced.

BPA Proposal--Optimum Use of BPA's Existing Legislative Authority. The proposal assumes an increased level of BPA involvement in the application of the one-utility concept based upon BPA's existing legislative authority. The proposal includes a new energy conservation policy that is feasible under existing legislative authority.

Under the proposal, BPA would provide services (load factoring, forced outage reserves, and load growth reserves) to Pacific Northwest utilities to integrate their new and existing non-Federal generating resources into the Federal Columbia River Power System (FCRPS) for their use. BPA would offer these services to Northwest preference and non-preference utilities for resources constructed either within or outside the region in order to facilitate coordinated regional operation of generation and transmission facilities.

The regional complement to the proposal assumes the continuation of cooperation agreements between Northwest power planning entities and also assumes that there would be incentives for utilities to enter into multiparty construction agreements to capture the economies of scale and other benefits and that the Pacific Northwest Utilities Conference Committee or some similar entity comprised of regional utilities would continue to participate in identifying the need for and characteristics of proposed regional generation resources.

Alternative 3--New Authority, Increased BPA Role in the Region. This alternative incorporates the basic concepts of legislation as originally introduced by the Northwest congressional delegation during the 95th Congress (S. 3418 and H.R. 13931) and again during the 96th Congress (S. 885 and H.R. 3508).

Under this alternative, a statutory planning process would be implemented involving the region's governors, local governments, utility and industry representatives, and the public. This process would be designed to guide BPA actions in regional power planning and development.

BPA would have direct purchase authority to acquire power from non-Federal power plants necessary to meet the firm loads of all the region's utilities. In acquiring resource capability under this alternative, first priority would be given to acquiring conservation, then renewable, and then conventional resources with priority given to high efficiency conventional resources.

BPA would have the ability to assist in the coordination of resource planning and development to the extent that it would be responsible for supplying power to meet utilities' and industries' loads. However, utilities would have the option to continue to plan and build resources and distribute power to meet their loads. Under this alternative, BPA would be better able to implement the one-utility concept than under previous alternatives through its active involvement in the purchase and sale of power.

Alternative 4--New Authority, Regional Energy Commission. This alternative incorporates some of the basic principles of legislation introduced by Representative James Weaver of Oregon in November 1977 (H.R. 5862) and in the 96th Congress (H.R. 4159). Under this alternative, a regional energy commission with authority to determine regional energy policy would be established, and in cooperation with BPA and regional non-Federal utilities, would provide integration, pooling, and marketing of all the electric energy in the region. Under the direction of the Commission, BPA would become the energy wholesaler for the Pacific Northwest, purchasing all energy generated or acquired by the participating utilities and assuming a full public utility responsibility to serve those utilities' loads. As part of this arrangement, BPA would undertake the construction or acquisition of such traditional resources as needed to meet loads which could not be met from conservation or renewable resource development. Under this alternative, the Commission would function as a Board of Directors to BPA, setting policy and directing BPA's actions.

Under this alternative, BPA would offer full requirements contracts to all participants in the Pacific Northwest. A participant would be any regional utility which sells all its electrical energy, either generated or acquired, to BPA.

In planning and construction of generating resources and major transmission facilities, the one-utility concept would become a reality. Participating utilities would assume primarily a distribution function. Participants would develop energy resources for their own use only where they could do so more economically than BPA or where a utility or group of utilities owned a resource that had not been authorized by the Commission and whose output would not be acquired by BPA. Nonparticipating utilities would operate essentially as they do now, being responsible for their own load forecasting, planning, system construction, and distribution. BPA would cooperate, to the extent feasible, with nonparticipants, and to the extent that nonparticipants requested, would integrate and coordinate resources and provide other services.

Impacts: Environmental consequences are first discussed in terms of generation, marketing, and transmission impacts associated with the operation of the entire regional power supply system (Federal and non-Federal components) as it exists today. The impacts identified include: the construction and operation of thermal generation plants with resultant impacts on air, land use and water; the adverse impact of hydroelectric facilities on fisheries, riparian vegetation and wildlife; displacement of fossil fuel generation with that from hydroelectric facilities; the adverse impact of BPA's direct-service industrial customers on the physical environment and the stabilizing effect on the regional power system of BPA sales to these industries; the adverse impact on land use of construction and operation of transmission lines; impacts of right-of-way maintenance on vegetation; the visual impact of transmission facilities; and the mitigating effect of conservation programs on the impacts of energy use and the fabrication and installation requirements of conservation technologies. Because the facilities described are in place, their impacts are seen as an irreversible and irretrievable commitments of resources. Further, these impacts serve as a baseline for comparing the incremental impacts of the proposal and alternatives.

In assessing impacts of the proposal and alternatives on future power system development, three interrelated areas were identified as having environmental significance. These areas include the impacts related to varying levels of regional cooperation and coordination, impacts of potential load-resource imbalances, and the influence of nonpower considerations on hydro system operation and impacts.

It was found that centralized coordination (regional interaction) as included in Alternatives 3 and 4, increases the accuracy of the regional forecast, broadens the range of resource options available, increases efficiency of resource use by permitting utilization of regional as well as interregional diversities, and provides a focus for input from special interests including representation of nonpower hydro resource concerns. In addition, it was concluded that centralized coordination minimizes the possibility of load-resource imbalances, reducing the possibility of both underbuilding and overbuilding generation resources.

In analyzing the potential impacts of specific future resources, the generic impacts of 21 different potential regional energy resources are discussed ranging from small renewable resources such as wind energy conversion systems to unconventional resource development including synthetic fuels. These generic discussions serve as the basis for evaluating the impacts of five future resource scenarios. The future resource scenarios presented are based on a "worst case" analysis. As such, the scenarios are conjectural and have been designed in an attempt to overcome the limitations of information which is currently available. These scenarios include 100 percent renewable resource development (Scenario A), maximum conservation (Scenario B), 100 percent coal-fired generation (Scenario C), 100 percent nuclear generation (Scenario D), and mixed coal-fired and nuclear generation (Scenario E). A sixth scenario (Scenario F), summarizing the NRDC alternative scenario, has been included in the FEIS to reflect NRDC's estimation of the technical potential or extent to which the region could rely upon a combination of conservation and renewable resource development.

The impacts resulting from these scenarios vary widely, ranging from large amounts of localized and even regional air emissions from coal generation to dispersed and remote emissions from small-scale renewable resources. Transmission requirements were found to be greatest under Scenario A due to its reliance on numerous generating facilities. Fuel transportation impacts would be greatest with coal development as in Scenario C and E as would risks to human health from air emissions.

Although nuclear development poses little risk from air emissions, it does involve radiological impacts.

In addition to evaluating impacts of potential future resources, this document discusses the change in the impacts of the existing generation, conservation, marketing and transmission practices that would result from implementation of the proposal or alternatives. Generally, it was concluded that the proposal would provide for continuation of traditional operational and planning approaches with the exception of an added emphasis on conservation. The first and second alternatives would most likely result in limited flexibility with regard to resource planning and would also result in operational restraints favoring maximum power production. Conversely, Alternative 3 and 4 would place a greater emphasis upon adopting a diversified resource base, thereby maximizing future planning flexibility and making possible the routine consideration of nonpower interests in the river system such as fisheries and irrigation demands.

Conclusions: The most fundamental conclusion reached in this analysis is that the one-utility concept offers environmental, economic, and technical advantages in the development and operation of a regional power supply system, which increases as the application of the concept is increased.

Additionally, it was concluded that there are no viable alternatives to the one-utility concept for the existing PNW electrical power system. Rather, only alternative approaches or mechanisms for implementing this concept are realistic. Accordingly, in presenting the proposal and alternatives, the major variable is the degree to which this concept is employed in the future development and operation of the Pacific Northwest power supply system.

Alternatives 3 and 4, which provide for a formalized, stable, and comprehensive regional power planning process, are environmentally preferable. Several considerations presented in the text which support this conclusion are:

1. As a result of formalized decisionmaking processes embodied in these alternatives, there is greater assurance that nonpower considerations will be routinely considered in the use of regional hydro resources.

2. This decisionmaking process would also minimize uncertainties regarding a regional load-resource balance, and would minimize the necessity for reliance upon extraregional resources.

3. Further, the planning processes would require that a greater emphasis be given to adopting a more diversified resource mix, including consideration of renewable or unconventional resources, which would decrease the impacts associated with the development and operation of conventional thermal resources and the regional hydroelectric system.

For the above reasons, Alternatives 3 and 4 are considered to be environmentally preferable alternatives. However, because these alternatives are not within BPA's current authority, the proposal was selected because it relies only on BPA's existing authorities.

Controversy. Controversy exists at all levels of electric power planning and development in the Pacific Northwest. In this sense, controversy includes not only disagreement over the extent of impact but also disagreement over the substance of the proposal and alternatives.

Included in this controversy are the issues of rates (both design and level), allocations (preference customers' rights, service to BPA's direct-service industries, etc.), future resource development including the extent of the region's reliance upon conservation (voluntary versus mandatory measures), level of BPA authority to purchase power resource capability, effect of BPA services on resource development, and the degree of public and State involvement in regional power planning decisions.

Only the latter issues relative to resource alternatives and institutional checks and balances are discussed in this EIS. The controversy surrounding the development of rates is discussed in BPA's 1979 Wholesale Rate Increase Final EIS (DOE/EIS 0031 F) and those issues relative to allocations will be discussed in BPA's Allocation EIS currently under preparation.

Unresolved Issues: There are two major unresolved issues confronting electric power planning in the Pacific Northwest. The first is the outcome of ongoing legislative efforts which could greatly alter the regional power planning process in the Pacific Northwest as well as BPA's role in that process.

The second issue is the future power resource mix to be developed in the Northwest. Resolution of this critical issue is dependent upon the development of regional power planning processes or new technological advances.

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Chapter I

OVERVIEW

O V E R V I E W

FOREWORD

Given the unique character of the Pacific Northwest and its resources, uncertainties about its future demand for power, the pluralistic nature of its power industry, its existing power planning arrangements, the constraints of political reality, the feasibility of existing energy technologies, the experimental nature of future technologies, and the serious power planning problems the region confronts, the question arises: What is the best practical way to meet future regional electric energy demand cost-effectively, to avoid the social and economic costs of energy shortages, to minimize adverse environmental impacts, and to conserve nonrenewable resources?

Numerous alternatives have been suggested and considered. From that process has emerged a Bonneville Power Administration (BPA) proposal. The BPA proposal consists of two principal elements: (1) optimum use of existing authority, including adoption and implementation of an effective and feasible energy conservation policy, to achieve a "one-utility" concept/goal in an expeditious and timely manner, and (2) endorsement in principle of additional authority that would reinforce achievement of that goal.

What follows in this overview is an examination of the circumstances underlying the selection of the BPA proposal, a summary of the proposal and alternatives, and an explanation of the BPA Final Role Environmental Impact Statement (EIS).

INTRODUCTION

This overview summarizes some of the salient features and basic purposes of the BPA Final Role EIS. The overview will also provide an explanation of why and how the Role EIS was undertaken, and will set the stage for the more detailed analyses which are contained in the remainder of the statement. It is not intended to stand alone as a complete summary of the Role EIS, but it should provide the reader with an intelligible "short course" characterization of what the Role EIS is all about.

This overview discusses the following topics:

1. BPA legislative authority

2. BPA mission and goals

3. Guiding principles

4. Setting (including description of the regional and Federal electric systems and the Hydro-Thermal Power Program)

5. Judicial decisions

6. Relationship of the original Draft Role EIS to the Revised Draft and Final Role EIS

7. The BPA proposal: selection criteria

8. The BPA proposal: key elements

9. Alternatives

10. The ranking alternative

BPA LEGISLATIVE AUTHORITY

BPA operates under the provisions of several Federal statutes, the two most important of which are the Bonneville Project Act of 1937 and the Federal Columbia River Transmission System Act of 1974. Other legislation significantly affecting BPA includes the Flood Control Act of 1944, the Pacific Northwest Regional Preference Act of 1964, and the Grand Coulee Third Powerhouse legislation of 1966.

The Bonneville Project Act has three key power planning features. First, the Act directs the Administrator to construct and operate a regional transmission grid to interconnect generation and to transmit electric energy to markets. Second, the Act contains a "preference clause" which requires that preference and priority in the sale of Federal power be given to publicly owned and cooperative utility systems. Third, the Act does <u>not</u> grant BPA the authority to own or construct any generating plants. BPA markets power (1) generated at other Federal agency hydroelectric plants, and (2) acquired by exchange or net-billing arrangements from non-Federal facilities.

The Transmission System Act is significant because it puts BPA on a self-financing basis. As has always been the case, all costs of the Federal Columbia River Power System, including all costs associated with BPA acquisition of power from whatever source, must be recovered from rates paid by BPA's customers. None of these expenses is to be paid by the U.S. Treasury or the Nation's taxpayers. Before the Transmission System Act, however, after turning over to the Federal Treasury all its receipts, BPA had to obtain congressional appropriations every year for capital investment and operating expenses. The Transmission System Act reinforces the self-financing policy and eliminates the roundabout need for BPA to obtain annual appropriations. All BPA receipts are now deposited in a special BPA fund in the Treasury from which BPA may make expenditures, if they are included in BPA's annual budget submitted to Congress, without further congressional appropriation.

Among the key legislative authorities and responsibilities by which BPA is bound are the following:

- BPA is the marketing agent for virtually all electricity generated by Federal hydro projects in the Pacific Northwest.

- BPA is to market Federal power so as to encourage the widest possible diversified use at the lowest possible rates consistent with sound business principles.

- BPA must give preference and priority in the sale of Federal power to public bodies and cooperatives.

- Pacific Northwest consumers shall be guaranteed first call on electricity generated at Federal hydroelectric plants in the Northwest; only surplus power (power which cannot be sold or conserved for later sale in the region) generated at Northwest Federal dams can be marketed by BPA outside the region.

- BPA's wholesale power rates must recover the cost of producing and transmitting Federal and other acquired power, including timely repayment of the Federal investment, with interest.

- Construction costs of Federal projects allocated to irrigation that are beyond the ability of irrigation water users to repay shall be charged to the Federal Columbia River Power System.

- BPA may establish uniform rates throughout the region to extend the benefits of an integrated transmission system and encourage the equitable distribution of electric energy.

- Rates must be adjusted at least once every 5 years.

- BPA contracts for the sale of power cannot exceed 20 years.

- BPA contracts for sale of power to nonpreference utilities must be cancelled upon 5 years notice if the power is needed to satisfy requirements of preference customers.

- The Federal transmission system shall be constructed to:

    1. serve BPA's customers,

    2. maintain the stability and reliability of the Federal system,

    3. integrate power from Federal and non-Federal generating units, and

    4. provide interregional transmission facilities.

- BPA may issue and sell up to $1-1/4 billion of bonds to the U.S. Treasury, at interest rates comparable to rates prevailing in the market for similar bonds, to assist in financing transmission construction.

- Proceeds from the sale of such bonds and all BPA receipts must be deposited in a special BPA fund in the Treasury from which expenditures can be made without further appropriation, provided they are included in BPA's annual budget submitted to Congress.

- Among the things for which BPA can spend money from the BPA fund are the following:

    1. building, operating, and maintaining transmission facilities,

2. transmission research and development,

3. power marketing,

4. short-term purchases of power to meet deficiencies and purchases of power as an agent for others if paid for with their funds,

5. emergencies, and

6. interest payments and repayment of the Federal investment.

- Excess power can be exchanged to secure economical operation or to meet demand in an emergency.

Many of these provisions were enacted into law when economically feasible hydroelectric energy resources were far from fully developed and when electric service was not universally available throughout the Pacific Northwest, particularly in rural areas. Moreover, when the Bonneville Project Act was enacted, the Nation was in the midst of its most serious and sustained economic depression. There was an urgency about public works in general and development of multipurpose water resources projects in particular. World War II ended the Great Depression and focused the Nation's attention upon the urgent need to produce military materiel, the production of which was greatly facilitated by the availability in the Northwest of large blocks of hydroelectric power.

Given the circumstances of a Great Depression followed by a World War, and recognizing the state of electrification in the region at the time and its promise for a better life for all, it is not difficult to understand how phrases such as "widest possible use" and "lowest possible rates" came to be carved into the pieces of authorizing legislation for BPA. Today, electricity is available virtually everywhere throughout the Northwest; it is recognized that it is an indispensable commodity which consumers value highly and the costs of which they are willing and able to pay, and that other interests such as protection of environmental quality and conservation of nonrenewable energy resources--matters of only modest concern 30 or 40 years ago--have only recently become elevated in national and regional importance.

The point is, times have changed. The issues <u>then</u> are no longer exclusively the issues <u>now</u>. For example, for the first time in the region's history, the real costs of electric energy have begun to rise--dramatically. For another example, there is now much more concern over the availability and cost of nonrenewable energy resources, particularly oil and gas. And for yet one more example, as the Columbia River and its principal tributaries approach optimum development, there are now more seriously competing demands upon this renewable resource. Clearly, the region is confronted with a new and different challenge.

BPA MISSION AND GOALS

BPA's mission, as it has developed over the decades in response to its legislative mandates, is quite straightforward. It is to help assure a viable electric energy system in the Pacific Northwest while balancing economic, technical, and environmental considerations. BPA is responsible for:

1. marketing power from Federal hydroelectric projects as well as power acquired from other sources,

2. integrating the operations of the region's generating and transmission systems in cooperation with other entities in the region, and achieving, as nearly as practicable, the economic and environmental benefits possible from a single-system operation (i.e., the one-utility concept), and

3. constructing transmission facilities to integrate and transmit the electric power from Federal and, when requested, non-Federal generating units, providing service to BPA customers, furnishing inter-regional transmission capabilities, and maintaining the electrical stability and reliability of the Federal system.

Consistent with the existing statutes under which it operates, and to help shape and guide its mission and keep it on track, BPA's goals are to:

1. maximize the benefits to society from the Federal investment in the region's electric power facilities;

2. conserve energy and other resources;

3. preserve and enhance environmental quality;

4. promote a safe and reliable electric energy supply for the region and for interconnected regions;

5. achieve an equitable sharing of costs among those receiving benefits from the Federal investment in the region's power facilities;

6. make timely repayment to the Treasury of the Federal investment in the region's power facilities, plus interest, and recover all other costs of that system through BPA revenues from its ratepayers; and

7. pursue technical and economic efficiency in production, transmission, distribution, and use of electricity.

Except for agency-specific requirements, such as BPA's obligation to repay the Federal investment in, and to recover all other costs of, the Federal Columbia River Power System, BPA's goals and the Pacific

Northwest's goals with respect to the region's electric power system can be assumed to be the same.

Invariably, statements of missions and goals sound platitudinous. No one seriously opposes maximum benefits to society, balance between demand and supplies, safe and reliable electricity, equitable sharing of costs, environmental quality, or energy conservation. It is obvious, however, that some of these goals sometimes conflict with one another and that choice of programs and policies will often involve reasoned trade-offs among goals. For example, the goal of a reliable and safe power supply is not always compatible with the goal of conserving resources.

Much can be done to reduce incompatibilities and to optimize outcomes. But some people assign higher values to certain goals than to others. Not everyone supports the same goals with equal intensity. And, given a set of goals such as BPA's, different individuals and interests could easily reach different conclusions when it comes to decisionmaking on a particular plan or program.

The principal importance of BPA's goals is that they can elevate everyone's sensitivity to what it is that BPA's programs are fashioned for and, assuming the goals are made an important part of day-to-day agency operations and policymaking, ensure that, in the formulation and execution of programs, each goal will be considered, none will be overlooked, and when some must be subordinated to or balanced against others, it is done with full awareness of that fact and not as a matter of neglect or indifference.

GUIDING PRINCIPLES

The electric power problems confronting the Pacific Northwest can be fairly well identified and will be described shortly. What is at issue is their solutions. A systematic way to explore for ideal solutions and to assess their suitability can be found in the context of goals and objectives. What is it the region wants?

BPA's goals as described above remain worthy. But goals tend to be broad and general. They are often the kind of "motherhood" and "apple pie" maxims to which most everyone can subscribe, but which lack sufficient specificity to lead directly to solutions.

The following regional electric energy objectives contain a higher level of detail to help in the identification of ideal future policies under which BPA and the region as a whole might operate. Being more specific, however, means they may also be more controversial. They are, however, the product of an extensive environmental impact statement process, and extensive congressional hearings in Washington, D.C., and in the region. Additionally, the last four objectives represent specific provisions contained in recent legislative proposals.

1. Adequate Power Supply. The region should seek an environmentally acceptable and economically sound power supply which adequately balances electric energy supply and demand. BPA and regional utilities should provide system reserves necessary to insure a stable power supply.

2. Conservation as a Resource. Conservation should be viewed as an energy resource, all feasible cost-effective energy conservation should be encouraged, and conservation should be funded by ratepayers as an energy resource to reduce regional needs for additional generation.

3. Alternative or Renewable Resources. Where feasible and cost-effective, development of alternative or renewable resources should also be funded as a resource to increase regional energy supply and reduce regional needs for conventional thermal resources.

4. Cost-Based Rates. Cost-based wholesale power rates should be retained as the basis for establishing rates, but a marginal-cost test should be used to evaluate and fund conservation programs and alternative or renewable resources. Rates should be kept as low as possible for all ultimate consumers by utilizing cost-effective and feasible conservation, renewable resources, and conventional resources.

5. BPA Responsiveness. The regional orientation of BPA and its interaction with State, local, and public interests should be strengthened in order for it to respond better to regional needs, consistent with national policy goals and objectives.

6. Regional Power Supply Planning. Coordination of regional, State, and local power supply and transmission planning should be encouraged.

7. Regional Participation. A mechanism for the Pacific Northwest ratepayers, the States, local government agencies, utilities, environmental and other interest groups, and BPA to participate jointly in power supply and transmission planning should be provided. Means for effectively involving the general public in regional power planning should also be improved.

8. State and Local Retail Rate Control. The responsibility of State public utility regulatory commissions and public, municipal, and cooperative utilities to set retail rates for regional consumers should continue.

9. State Control of Sites. Present State control over siting of generating resources should be retained to enable States to exercise their responsibility for protecting the local environment and regulating utility resource development, consistent with regional and national energy policy goals and objectives.

10. One-Utility Transmission Development. Development of the regional integrated transmission grid based on the one-utility concept should continue.

11. Self-Reliance. The region's ratepayers should bear the full costs of the regional power system without subsidy.

12. Preference Clause. The preference clause should be preserved, as should the right of the public to form new public bodies and cooperatives.

13. Power Purchase Authority. BPA should first invest in feasible and cost-effective conservation and renewable resources and, if these resources are insufficient to meet projected demand, BPA should then be authorized to purchase the output of conventional generating facilities. Costs of acquiring all resources should be borne exclusively by ratepayers. In turn, the region's ratepayers' investment in the Federal Columbia River Power System should be used to back future regional investments in energy resources.

14. Extend Regional Preference. The principle of regional preference should be extended to include not only Federal hydropower but BPA-acquired regional non-hydroelectric power resources as well, so that only power which turns out to be surplus to regional needs (because of abundant streamflow conditions, for example) can be exported outside the region.

The One-Utility Concept

With more than 100 utilities in the region, varying markedly in size and resources, it would be painfully inefficient for each to do independently all the things it deems appropriate to ensure that its own loads are met. Careful analyses of alternatives have demonstrated that coordination of plans and actions, and integration of facilities as part of a comprehensive regional plan, is cost effective. It is also the most promising way to encourage and achieve effective energy conservation.

The 14 guiding principles listed above have this common thread running through them: to the extent feasible, electrical energy planning and decisionmaking, as well as day-to-day operations, should be coordinated. And, to the extent feasible, that coordination should include development of regional forecasts of electric energy demand, adoption and implementation of conservation programs, selection of generation technologies and mixes, generalized siting of energy facilities, and regional integration of power facilities. That is the "one-utility" concept. Among idealized prototypes, the one-utility concept, if achieved, is most likely to meet the region's goals and objectives, and solve its serious electric power problems.

Clearly, if there were only one regionwide electric utility serving the entire Pacific Northwest and if that single utility (1) owned and managed all of the region's electric energy resources, (2) had a public utility responsibility for meeting all reasonable loads without discrimination, (3) was obliged to keep its costs as low as possible, (4) had authority to implement conservation and acquire renewable resources, and (5) was required to provide for regional participation in its decisionmaking processes, it would greatly facilitate attainment of most if not all of the objectives enumerated above.

However, a single regionwide electric utility serving the entire Pacific Northwest is not a realistic prospect for the region. Without overlooking the advantages of pluralistic ownership; i.e., local control and competition, the "second-best" realistically achievable arrangement from a <u>technical</u> point of view is for all or most of the region's many utilities to plan and act as if they were one with respect to regional electric energy issues.

One compelling concept about which there is very widespread agreement is that whatever regional electric energy goals are to be met, they should be met in the most efficient way practicable. Under the "one-utility" concept, the region's power facilities, including conservation programs and renewable resources, would be operated as much as possible as though they were planned, owned, and managed by a single regionwide entity, with the highest practicable level of coordination and interutility cooperation. The conclusion is technically inescapable that the "one-utility" concept offers the greatest promise for minimizing power facilities, adverse environmental impacts, costs, and commitment of the Nation's scarce physical resources, and at the same time, for ensuring that the region's appropriate demand for electric energy, whatever that may be, is satisfied.

SETTING

Comprehensive Planning

The Pacific Northwest, consisting primarily of the States of Idaho, Oregon, and Washington, plus that portion of Montana that lies west of the Continental Divide, has approximately one-third of the total hydro-electric potential of the United States, more than any other region in the Nation. From the standpoint of electric power planning and development--past, present, and future--this unique characteristic, more than any other, has served to influence the development of the power supply system in the Northwest, distinguishing it from other regions of the country.

Until it became technically and economically feasible to build dams across the mainstem of the Columbia River, most of the water resource development in the Pacific Northwest proceeded on a relatively haphazard and uncoordinated basis. But as technology improved and the region's economy expanded, additional development of its water resources became progressively more attractive to farsighted planners. And it also became clear to them that comprehensive, rather than piecemeal, river basin development should be investigated and pursued. First, they saw that many of the potential hydro projects could be built to serve immensely beneficial multiple purposes and would be the least cost way to achieve those purposes. And second, they concluded that, rather than approach water resource development on a project-by-project basis, comprehensive development throughout the river basin could substantially increase overall benefits and yield optimum returns on investment. What was needed was a coordinated plan for the entire Columbia River basin.

Except for some modest interutility power connections, little if any coordinated planning occurred in the Northwest prior to 1927. In that year, the Corps of Engineers launched a comprehensive study of the development potential of the Columbia River basin in the United States. The study, called the "308 Report," recommended 10 major hydroplants along the mainstem of the Columbia River starting at Bonneville, 146 miles upstream from the mouth, and ending at Grand Coulee, 597 river miles above the mouth.

In addition to the proposals for mainstem projects, the "308 Report" recommended a plan to meet requirements for flood control, navigation, hydropower, and irrigation. Additionally, it recommended a number of storage projects for construction in the upper reaches of the basin. The "308 Report," published in 1932, was the first official plan for large-scale comprehensive development of the basin.

Construction of Bonneville Dam was begun by the Corps of Engineers in 1933, during the depths of the Great Depression. The next year, the Bureau of Reclamation began construction on Grand Coulee Dam. Both of these Federal dams were started as emergency public works projects.

By 1937, Bonneville Dam was nearing the stage of initial power production. Several legislative proposals were advanced in the Congress to provide for administration of the project. Some proposals would have placed responsibility for development of the entire river basin in the Bureau of Reclamation. Others would have vested the transmission and marketing functions, as well as project construction, in the Corps of Engineers. Still others would have established a Columbia Valley Authority similar to the Tennessee Valley Authority.

Because regional planners recognized that any administration of Federal hydroelectric projects in the Northwest should provide for a unified program of multipurpose development, and because there were conflicts as to which Federal agency, existing or new, should administer the projects, a compromise was struck by creation of a "provisional" agency within the U.S. Department of the Interior to market the power from Bonneville Dam (and subsequently from all Federal dams in the region, except for a small Bureau of Reclamation project--Green Springs--in southwestern Oregon). The new agency, created in 1937, was the Bonneville Power Administration (BPA). The Federal dams, however, continued to be built and operated by either the Corps of Engineers or the Bureau of Reclamation; BPA markets the power and recovers all of the power costs, including timely repayment of the Federal investment plus interest.

BPA completed its first transmission line from Bonneville Dam to the City of Cascade Locks, Oregon, in July 1938. Gradually, a Federal transmission network took shape as additional Federal generating units came on line and additional publicly owned, cooperatively owned, and investor-owned utilities, plus some electroprocess industries, became customers of BPA.

Pacific Northwest Electric Power System

As of January 1, 1978, the Pacific Northwest's rated electric generating capacity totaled almost 37,000 megawatts, of which approximately 79 percent was installed in hydroelectric projects. More than 14,250 of the 31,000 megawatts were installed in Federal hydroelectric plants, the output of which is marketed by BPA. Almost 10,000 of the total 31,000 megawatts consists of non-Federal hydroelectric capacity. The remaining approximately 6,500 megawatts consists of existing non-Federal thermal generating capacity, 80 percent of which is installed in five large generating projects--the Centralia coal-fired plant located between Portland and Seattle, the dual-purpose N-Reactor on the U.S. Department of Energy reservation at Hanford, Washington, the coal-fired Jim Bridger Units 1, 2, and 3 at Rock Springs, Wyoming (two-thirds of the output of which is used to meet Pacific Northwest loads), the coal-fired Colstrip Units 1 and 2 in Montana (half of which is used to meet PNW loads), and the Trojan nuclear powerplant 42 miles north of Portland at Rainier, Oregon. The remaining existing thermal powerplants in the Northwest are either new combustion turbines or new combined-cycle units used primarily for short-term peaking or during periods of poor water conditions, or small and relatively old steam and diesel units pressed into service only when the region is threatened with serious power shortages.

The construction of Federal multiple-purpose hydroelectric dams in the Pacific Northwest reached a peak in 1952 when 13 dams were under construction and has steadily declined since then. Presently, Grand Coulee pump generators 9 through 12 and Bonneville Dam Second Powerplant are under construction. Bonneville Second Powerplant will add 182 MW of average annual energy and 558 MW nameplate capacity (including fishwater units). Grand Coulee pump generators 9 through 12 will add additional (200 MW) peaking capability only. Cougar Additions, Strube Dam and generation, and Libby Dam Additions are scheduled for commercial operation from November 1985 to September 1986. McNary Second Powerhouse is authorized but no construction date is set.

However, the outlook for many more large hydropower projects is dim. While half of the power potential remains unharnessed, particularly on tributaries of the Columbia River, almost half of the unharnessed water power lies within wild and scenic rivers, wilderness, and recreation areas. Prospects are better for small hydro projects which make use of existing structures. The Corps of Engineers and the Water and Power Resources Service are conducting studies requested by Congress to assess the total available potential. The Corps of Engineers is in the process of screening this total potential to identify a list of projects which merit further study. The screening process is designed to pick out projects which appear to be economically feasible while meeting environmental tests. Further screening will yield a smaller list of projects which merit a high priority for early development.

The Corps of Engineers' role, with respect to the Federal Columbia River Power System, includes more than just power production. Their projects in the Federal Columbia River Power System were authorized as multipurpose projects of which hydropower is only one function. Other functions include: flood control, navigation, irrigation, recreation, and minimum streamflows. Therefore, the Corps of Engineers must take into consideration purposes other than power generation when scheduling the available water in the river system through their projects. The projects are planned, constructed, and operate in cooperation with the States and other Federal agencies to provide for maximum utilization of the resources. Further, Congress has directed that in those areas lying wholly or in part west of the 98th meridian, any such uses must not conflict with any beneficial consumptive use, present or future. Certainly one of the most common consumptive uses from the Columbia River System is irrigation. Accordingly, in the long-range planning studies, the Corps of Engineers, Bonneville Power Administration, and the Northwest Power Pool all assume this policy will continue.

In addition, a number of thermal powerplants, ranging from relatively small oil-fired combustion turbines to very large coal-fired and nuclear powerplants, with a combined capability of more than 13,000 megawatts, are scheduled for installation in the region within the next decade.

The Federal Columbia River Power System

The Federal Columbia River Power System (FCRPS) is comprised of three principal elements: (1) the hydroelectric generating projects constructed and operated by the U.S. Army Corps of Engineers and the Water and Power Resources Service (WPRS) within the Pacific Northwest region, (2) the electric transmission system constructed and operated by the Bonneville Power Administration, and (3) power acquired by BPA through exchanges and net-billing.

BPA, which became an agency of the new U.S. Department of Energy in October 1977 after being part of the Department of the Interior for its first 40 years, is the marketing agent for the power produced by the Corps and WPRS projects. BPA also acquires some shares of the capacity of thermal generating plants constructed by non-Federal publicly owned entities such as municipal electric utilities and joint operating agencies. BPA melds its acquired power with the Federal hydropower and markets the melded product wholesale to electric utilities, other Federal agencies, and certain (direct-service) industrial customers. BPA also "wheels" (transmits) power over its facilities for others.

BPA has always been obliged to repay the Federal investment in the FCRPS and to pay all FCRPS operating costs from revenues. However, prior to 1975, BPA had received all of its operating and capital investment funds by means of annual appropriations from Congress. BPA is now authorized to sell bonds to the U.S. Treasury to raise capital funds to finance the construction of new transmission facilities. And on behalf of the FCRPS, BPA is obligated by statute to set its power and wheeling charges at "the lowest possible rates to consumers consistent with sound business principles" that will fully repay any bonds it has issued and fully recover all of the costs 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 various statutes under which BPA operates require that preference and priority be given to public bodies and cooperatives in the sale of FCRPS power. The Bonneville Project Act, Section 4(a), states that: "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 customers, 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 1978, BPA marketed power from 30 Federal hydroelectric projects to 147 customers in the Pacific Northwest--116 publicly or cooperatively owned utilities, 8 investor-owned utilities, 6 Federal agencies, and 17 direct-service industrial customers. For 98 of its utility customers, BPA is the sole source of power supply. BPA markets about one-half of the electric energy produced in the Pacific Northwest and provides about four-fifths of the region's electric power bulk transmission capacity.

BPA's transmission system consists of about 12,500 circuit miles of high-voltage transmission lines and 345 substations. The BPA transmission system constitutes America's largest high-voltage transmission network and is the "backbone" grid to which all interconnected utilities in the region are tied for reliability and economic efficiency. BPA also markets and exchanges electric power interregionally over the Pacific Northwest-Pacific Southwest Intertie, and in Canada over interconnections with utilities in British Columbia.

The First Three Decades (1937-68)

BPA's first three decades of operation, from 1937 to the mid-1960's, were by and large a period of abundantly available Federal power. BPA was generally able to meet the net requirements of all of its customers-- preference utilities, investor-owned utilities, and direct-service industries. BPA charged essentially the same rate to all these customers.

Two major developments occurred during this period of power abundance. First, voters in the State of Washington elected to establish many more publicly and cooperatively owned power agencies than were established in Idaho, Montana, or Oregon. For example, today about 57 percent of Washington State consumers are served by public bodies and cooperatives, while in Oregon, Idaho, and Montana, respectively, 20, 17, and 24 percent are served by public bodies and cooperatives. The choice at the time was based as much, if not more, on political ideology as on power costs since BPA had sufficient power to meet the needs of investor-owned utilities, too. Moreover, larger utilities that built additional generation of their own were often able to do so at relatively low costs that were more or less equivalent to BPA's rate of power.

Second, starting in 1940, direct-service industries--principally aluminum reduction plants--came to the region. By the end of World War II, 5 aluminum plants, 4 of which were established during the war to meet war production goals, were operating in the Northwest. Today there are 10 aluminum reduction plants, the newest of which went into operation in 1971. In addition, major expansions occurred from 1950 through 1968 in existing plants. An important characteristic of the direct-service industries is that they provide a market for interruptible power which in earlier years would have been wasted.

There is a distinction between power planning and actual power operations. The power system is planned so that, ideally, total demand for electricity in the Pacific Northwest is met, even under critical water conditions. The portion of BPA's industrial loads that can be contractually interrupted is included in that total demand. Under actual power system operations, however, the 25 percent interruptible portion of BPA's industrial loads can be and has been curtailed at any time, for any period, and for any reason. In addition, a significant portion of the remaining direct-service industrial load is available as power system reserves.

The Hydro-Thermal Power Program

Until the mid-1960's, virtually all of the electricity generated in the Pacific Northwest was hydropower. Regional planners and engineers had long recognized, however, that there was a limited amount of economically feasible and environmentally acceptable hydro energy potential. As that potential was progressively developed and as the region's population, economy, and demand for electric energy continued to grow, planners and engineers concluded that thermal powerplants would have to be built to supplement dams in supplying electricity to meet growing loads. Additional low-cost peaking power could continue to be obtained by installing additional hydro generator units, primarily at existing dams, and some smaller-scale hydro energy potential could also be developed. But the region's power system would gradually change from virtually all-hydro to mixed hydro-thermal.

The concept of blending hydro and thermal resources together in an optimum fashion was not new. Its genesis dated back many decades. The idea fulfilled the predictions of regional planners and engineers in the Pacific Northwest and elsewhere who, since the early 1920's, recognized the advantages of integrating hydro peaking capacity with thermal energy. In 1955, the United States Senate Public Works Committee directed the Corps of Engineers to review its "308 Report" by restudying the Northwest's hydropower potentials "as part of a combined hydro-thermal system." Complying with that congressional directive, the Corps published a comprehensive revision of the "308 Report" in 1958 which spelled out the concepts of joint operation of hydro projects with thermal projects. These concepts were developed into an action program by the Joint Power Planning Council in 1968 called the Hydro-Thermal Power Program (HTPP).

While some of the details of the Hydro-Thermal Power Program are complicated, the essential features are quite simple. Basically, it was designed to fulfill two key objectives. First, it should permit development of an adequate and reliable supply of power to meet future Northwest electricity demand at the lowest practicable cost. Second, the long-range plan should achieve optimum combination of the region's generating and transmission resources--hydro and thermal, Federal and non-Federal, public and private, existing and planned. Even before the program was approved, it was also assumed that an optimal future power system, which would be able to meet electric energy demand with (1) substantial flexibility as far as plant siting is concerned, and (2) the most efficient and least use of generation and transmission resources, could be structured to pay maximum effective attention to protection of the environment.

To meet these twin objectives, the region's utilities and the Federal Government would plan, build, and operate the region's entire electric system as though it were under a single ownership--the "one-utility" concept. Thermal power would be integrated with hydropower. Markets would be assured for the output of the largest and most economical thermal plants. Bulk transmission, peaking capacity, forced outage reserves, reserves for unanticipated load growth, and, when available, surplus hydro energy for thermal fuel displacement would be primarily Federal responsibilities. Building the most economical thermal powerplants timed, sized, and located to meet regional needs (instead of just the needs of the owners), and providing essential low-voltage transmission and distribution would be the key responsibilities borne by non-Federal utilities. An unprecedented high level of interutility cooperation would be the goal.

Phase 1 of the HTPP (1968-73)

The plan was conceived by the Joint Power Planning Council, which was organized in 1966 and consisted of 108 participating Pacific Northwest utilities and BPA. The plan was unveiled on October 22, 1968, and a year later, on October 27, 1969, was approved by the national administration. Implementation of the program was initiated by Congress in the Public Works Appropriations Act of 1970. The Act approved net-billing, the principle whereby BPA would acquire some of the publicly financed shares of the output of non-Federal thermal powerplants (an arrangement which is explained below). Authority to implement the remainder of the program through 1981 (Phase 1) was provided in the Appropriations Act of 1971. Thus, the Hydro-Thermal Power Program was launched. A list of the plants included in the HTPP are listed on page IV-31.

Perhaps the most important feature of Phase 1 of the HTPP is that BPA acquires some of the output of some of the proposed thermal powerplants through "netbilling." Under this arrangement, preference utilities (public bodies and cooperatives) have built and are building portions or all of certain thermal powerplants to meet their future power requirements. They furnish the output to BPA. BPA in turn bears the preference customers' shares of the costs of those powerplants, acquires the power output, and blends it with Federal hydropower. BPA then sells the blended product to its various customers, including the participating preference utilities. It "pays" those utilities for their shares of the powerplants' costs by reducing their annual bills for power purchases and other services from BPA. Three goals are accomplished: (1) financing costs for preference utilities to build powerplants are reduced (through lower interest rates) because of commitments by BPA to acquire output and pay costs, (2) BPA's power supply is augmented, and (3) costs are distributed to all consumers of BPA power.

Two unexpected events occurred to limit use of this approach to meet regional power demands. First, unanticipated skyrocketing costs for construction of new thermal powerplants began to exhaust BPA's net-billing capability earlier than anticipated. This occurred because thermal powerplant costs have been increasing much more rapidly than BPA wholesale power rates, which are based on blended hydro-thermal costs. If more thermal powerplants were to be built in addition to the four which are already covered under net-billing, the sums that BPA would be obligated to credit against preference customers' billings (reflecting thermal projects' costs) would exceed the sums they owe BPA (reflecting BPA's rates for blended hydro-thermal power). An unsatisfactory solution would be to hike very substantially BPA's wholesale power rates to participating preference utilities.

Second, and perhaps most importantly, a 1973 Treasury Department and Internal Revenue Service ruling prevents BPA's preference customers from using tax exempt bonds to finance additional thermal powerplants from which BPA would acquire more than 25 percent of the output, thereby eliminating an important financing cost advantage. Federal law provides that the interest payments from bonds issued by non-Federal public bodies are ordinarily not taxable, hence bondholders are willing to settle for a lower interest rate than would customarily be payable on taxable bonds of comparable risk. The 1973 ruling effectively ended the use of tax exempt bonds for construction of powerplants where the output would be acquired by BPA.

Although costs were the <u>coup de grace</u> for extending Phase 1, there were other complications as well. First of all, there are more than 100 independent, resolute, and strong-minded utilities in the region involved with the Federal Government in planning, building, and operating a coordinated regional power system. Coordinated effort is complicated by the fact that thermal powerplants introduce new and in some respects more serious environmental problems than the region has known in the past, and while none of these problems is necessarily insoluble or unmanageable, most require expensive control technologies, commitment of resources, and continuous monitoring and assessment. New thermal powerplants also produce electricity at costs many times greater than the costs of existing hydroelectricity, thus there is a natural competition among prospective consumers to gain a "proper" share of the low-cost hydroelectric component of the region's melded power base. Matters are complicated still further by the fact that the leadtime for construction of thermal powerplants is very long (in excess of 10 years), subject to slippage but pitilessly resistant to compression.

Finally, Phase 1 was inaugurated and implemented during a time when sharply higher energy prices and other factors infused load forecasting with growing uncertainties. Where BPA and the region's utilities were once able to develop forecasts of electric energy demand with breathtaking accuracy, the decade of the 1970's introduced qualms and significant revisions of earlier load forecasts. The 1970's also saw growing interest in the potential of new and alternative technologies. The state-of-the-art of new technologies is largely experimental at present; therefore it is difficult to gauge today the extent to which emerging alternative energy technologies will be applicable and suitable for deployment 10 or 20 years from now.

<u>Phase 2 of the HTPP (1973-75)</u>

Phase 2 was a short-lived attempt to overcome the elements that prevented Phase 1 from proceeding further--the approach of exhaustion of net-billing capability and the tax ruling. Under Phase 2, preference utilities, individually or jointly, were to build some of the new thermal powerplants, and individual preference utilities would buy the power output at actual costs. BPA was to act as the agent for public bodies and cooperatives and undertake arrangements to make it a workable scheme, short of paying for the new thermal powerplants either by net-billing or other means. These arrangements were to include BPA selling temporary powerplant surpluses, "shaping" generation to fit loads, and providing transmission and reserves.

A key element of Phase 2 was the willingness of preference utilities to forego their preference claims to Federal power now being sold to BPA's direct-service industrial customers (DSI's) when present contracts expire, thus permitting new long-term, power sales contracts to be signed with the DSI's. In return, the DSI's would provide the region with greater electric power reserves than those which the industries already provide, by virtue of the interruptible and modified firm power provisions of their contracts with BPA.

Two Federal court decisions, one in 1975 and the other in 1977, together with further skyrocketing costs, brought the regional aspects of Phase 2 to an abrupt halt and it was abandoned. (These decisions and their relationship to this Final Role EIS will be described shortly.)

The inability of BPA and power entities in the region to carry out portions of their responsibilities under the Hydro-Thermal Power Program in a timely manner injected great uncertainties into the region's electric power planning process. That inability to perform as expected resulted in part from the events and complications which limited use of the Phase 1 approach and the Federal court decisions which halted Phase 2.

The Current Regional Effort

Pacific Northwest utilities continue to cooperate in the planning and operation of the regional power supply system. Existing facilities are coordinated through the Northwest Power Pool and the parties to the Pacific Northwest Coordination Agreement. The Northwest Power Pool provides informal coordination of the FCRPS with the operations of the major public and private utilities in the region; the Coordination Agreement formalizes coordination to maximize the efficiency of the operation of the region's hydro resources. Individual utility load and resource forecasts are assembled into a regional forecast under the auspices of the Pacific Northwest Utilities Conference Committee (PNUCC), an organization of all of the public and private utilities in the West Group Area of the Northwest Power Pool, and the regional forecast is used as a basis for planning resources and preparing for potential deficits.

At present, power resources of the West Group Area consist of 29,505 megawatts of hydroelectric capacity, providing 12,037 average megawatts of firm energy, and 2,773 megawatts of capacity and 2,469 megawatts of firm energy from large thermal powerplants. Small amounts of power are also supplied by combustion turbines and other resources. Regional generating plants are shown in Figure IV-1. In addition, there are 1,708 megawatts of hydro peaking capacity under development which will also supply 44 megawatts of firm energy and 7,397 megawatts of thermal capacity in the process of construction with an expected firm energy output of 5,549 average megawatts.

Resources beyond those currently under construction are less certain. The West Group Area forecast takes into account thermal generating resources which could provide 5,936 megawatts of peak capacity and 4,452 megawatts of firm energy, but until these plants receive all of the permits necessary to allow construction, their completion cannot be regarded as a certainty. In anticipation of continued load growth in the region, utilities continue to plan other conventional resources which do not yet appear in the West Group Area forecast. Efforts are also underway to investigate the potential of cogeneration, biomass, geothermal energy, wind energy, and solar energy for providing power in the region, and to develop the information necessary to achieve the potential of these resources.

The regional transmission system consists of approximately 16,000 miles of high-voltage (230 kV or higher) transmission lines. The basic structure of the transmission grid (as shown in Figure IV-4) is complete, but there is a continuing process of maintaining existing lines, upgrading portions of the system, and adding new sections of line to enable the system to adequately provide for the region's transmission needs. Most high-voltage transmission lines are constructed by BPA, but utilities also independently undertake transmission developing in some cases. BPA and the region's utilities continue to cooperate to make efficient use of the regional transmission grid.

<u>Other Environmental Analyses</u>

This Final EIS examines a proposed <u>program</u> to make optimum use of BPA's existing authorities in the operation of the future power system. The proposal is evaluated in the context of BPA's <u>policy</u> or mission, to help assure a viable electric energy system in the Pacific Northwest, following a plan to do this through adherence to the one-utility concept. The proposal does not select any <u>project</u>-specific future resources of technologies to be developed or acquired. Accordingly, the Role EIS is regarded as a "tiered" EIS designed to discuss policy, planning, and programing matters and is not intended to present the level of detail of a project or action-specific EIS. Project or action-specific proposals will be assessed individually as they are formulated.

This "tiering" concept, which is encouraged by the Council on Environmental Quality (CEQ) in their NEPA regulations (40 CFR 1502.20 and 1508.28), provides for a focus upon the issues ripe for decision and their impacts. Currently in the Pacific Northwest the central issue is the selection of an alternative regional power planning process; legislative proposals being circulated in the region advocate the adoption of various alternative regional power planning processes.

The actions permitted BPA under the proposal include the continued construction of transmission facilities, the sale of power, the setting of wholesale rates, the provision of services (wheeling and load shaping), and development of pilot programs and demonstration projects in the areas of conservation and renewable resource development.

As in the past, BPA will, at the time a proposal originates, continue to prepare and circulate action or site-specific environmental documents or statements on major transmission proposals (FY 1980 Construction Program EIS), power sales contracts (Alumax and Addy EIS's), wholesale rate increases (FY 1979 Wholesale Rate Increase EIS), and demonstration of pilot programs (wind generation).

Environmental impacts of actions such as new generation projects prepared independently by the region's utilities would be assessed as required by State environmental policy acts (SEPA) in the case of Washington and Montana, or by the Energy Facility Siting Council in Oregon. If these actions were to become "federalized" by integration into the BPA main grid, then BPA would review any previous environmental analyses and either accept these analyses as adequate or conduct additional analyses as necessary.

However, should BPA acquire new authorities that would require it to formulate a new regional power program, providing for the acquisition of project-specific resources or generation technologies, then both the program and the projects would be the subject of additional environmental analyses.

JUDICIAL DECISIONS

On September 15, 1975, the U.S. District Court of Oregon ruled that the Bonneville Power Administration was obliged to prepare an environmental impact statement (EIS) in connection with a proposed modification of a contract to provide service to a proposed aluminum reduction plant. The modification sought to change the point of power delivery from Warrenton, Oregon, to Umatilla, Oregon, increase the reserves to be provided by the industry, and extend the contract term if other similar contracts were extended. A few months before that decision was rendered, a draft of an earlier EIS effort entitled "BPA Participation in Regional Interutility Cooperation" had been distributed for review. The September 15, 1975, decision specified, however, that the EIS was to include aspects of the Hydro-Thermal Power Program associated with the modified contract.

In response to that decision, BPA embarked on the preparation of a site-specific EIS for the aluminum plant in question (Alumax) and interlinked that EIS with a comprehensive "Role EIS" covering all of BPA's functions, not just its participation in interutility cooperation and not just aspects of the HTPP associated with a single proposed plant. Preparation of the comprehensive Role EIS was already underway and its linkage with the site-specific Alumax EIS was deemed appropriate because of the complex and more or less inseparable interrelationships between BPA, regional utilities, BPA's industrial power sales activities (including service to the proposed new aluminum plant), and the development of the regional power supply system.

On July 1, 1977, the U.S. District Court of Oregon ruled on another suit, brought by the Natural Resources Defense Council, that BPA was obliged to prepare a "programmatic" EIS on its long-range plans involving the development of electric generating facilities in the Pacific Northwest, again not just limiting the EIS to aspects of the HTPP associated with a single plant. In effect, this 1977 judicial decision ratified BPA's earlier decision to undertake preparation of a comprehensive Role EIS.

In 1968 and 1969, prior to enactment of the National Environmental Policy Act (NEPA), Phase 1 of the Hydro-Thermal Power Program was adopted by the region's utilities and BPA, and approved by the national administration. That program was designed to provide an adequate power supply for the Northwest through 1981. Subsequently, after enactment of NEPA, the extension of the Hydro-Thermal Power Program that came to be known as Phase 2 was agreed upon by BPA, its industrial customers, and the region's utilities. Phase 2 was designed to provide for additional generating capacity to satisfy the region's power needs through 1986 and beyond. It was toward the post-NEPA Phase 2 that the 1977 judicial decision addressed itself most particularly.

The 1977 court decision held that "BPA plays a pivotal role in HTPP and Phase 2" and it required that the kind of comprehensive and programmatic

EIS upon which BPA had already embarked must be prepared as a condition to satisfy NEPA if the HTPP were to be pursued. Specifically, the 1977 decision states that BPA is required by NEPA to prepare an EIS on all aspects of Phase 2 of the Hydro-Thermal Power Program or any followup program.

Although Phase 2 of the HTPP has been abandoned, it is recognized that similar cooperative arrangements are likely to occur within the region if regional power problems persist and as they become more serious. It is with this recognition in mind that this Role EIS has been prepared: to examine alternative planning arrangements many of which may be similar to the HTPP in concept and design.

In 1977, at nearly the same time as the NRDC vs. BPA decision, a draft of the Role EIS was published and distributed widely for review and comment. That multi-volume draft carried an imposing title: "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System, Including Its Participation in the Hydro-Thermal Power Program: A Program Environmental Statement and Planning Report." The document measured more than 7 inches thick and consisted of five volumes plus a Summary Report.

A large-scale citizen involvement program, including workshops and public meetings, unprecedented in the region, was conducted to familiarize the public with the complex and technical issues confronting energy planners. The program encouraged widespread review and comment on the draft, provided information to the public of the regional energy issues, and brought out voluminous citizen input on the content of the original Draft EIS.

In response to public and agency comments, departmental review, and the recent CEQ regulations for implementation of the procedural requirements of the National Environmental Policy Act, the Role EIS was reissued as a revised draft for additional public and agency comments.

RELATIONSHIP OF THE ORIGINAL DRAFT ROLE EIS TO THE REVISED DRAFT AND FINAL ROLE EIS

Aside from the important reorganization of the EIS into a more manageable size and format, the Revised Draft and Final Role EIS were significantly modified from the original DEIS, most particularly in response to reviewers' comments and also in response to rapidly changing circumstances including enactment of a National Energy Act and serious congressional efforts to enact major legislation affecting the Pacific Northwest's regional power system. Among other things, that proposed legislation also reflects national energy policy goals which assign higher priorities to energy conservation and to the development of renewable generation resources.

With respect to reviewers' comments on the original Draft Role EIS, inspection indicated four recurring comments, each of which has been addressed in this Final Role EIS:

1. Some reviewers felt that the original Draft Role EIS lacked an explicit action or program proposed by BPA. Based on comments received, some readers felt that the draft did not clearly focus upon either a recommended action from among the array of alternatives or that it did not identify the precise characteristics, including environmental impacts, of a hydro-thermal power program.

2. In the original Draft Role EIS, various environmental impacts to various alternatives were presented in various appendices. The intent was a "building-block" approach but some reviewers felt that this resulted in a diffusion of environmental impacts and alternatives, making comparison difficult. They claimed that this reduced the usefulness of the document as a decisionmaking tool in assessing alternatives and their impacts.

3. The original Draft Role EIS did not define a discrete and manageable set of alternative actions. Instead it assumed an almost infinite array of alternatives, both for the region and for BPA. While these alternatives were not criticized as being unrealistic, some reviewers felt it made it difficult to use the document in the selection of an option of choice. A preferred tack, and one that many felt would have enhanced the usefulness of the document for decisionmaking purposes, would have been to identify a limited set of reasonable alternatives (and their associated environmental impacts) that bound the likely options that are available to the region and to BPA.

4. Although there is a good deal of controversy over how much electric energy demand can, as a practical matter, be modified by implementation of energy conservation programs, the original Draft Role EIS was said to have given inadequate consideration to that potential. It would seem useful to readers and decisionmakers alike to be able to

identify a maximum credible regional and BPA energy conservation scenario, carefully distinguishing between what is theoretically possible and what is realistically achievable. That would provide a gauge of the extent to which realistic and cost-effective conservation offers genuine alternatives to large central-station generation scenarios.

Other criticisms and comments received covered an array of ideas including some that might be categorized as fanciful and unrealistic but also many others which were imaginative and useful and which represented genuinely constructive criticisms. However, the most important perceived deficiencies were the four enumerated above. In every case, a diligent effort was made to carefully assess each comment received and to address the matter appropriately in the Revised Draft and Final Role EIS.

THE BPA PROPOSAL: CRITERIA FOR SELECTION

It was earlier mentioned that one of the perceived deficiencies in the BPA's Draft Role EIS was lack of an explicitly identified BPA proposed action or program among the numerous alternatives discussed. Among other things, the Revised Draft Role EIS more clearly identified such a proposal. It will be described shortly.

At the time the Revised Draft Role EIS was being prepared, potentially farreaching Northwest power legislation was being considered in the Congress. If that or similar legislation is enacted, BPA's authority and responsibilities would be very significantly altered.

One of the proposed bills, originally introduced in the 95th Congress (S. 3418 and H.R. 13931) as the "Pacific Northwest Electric Power Planning and Conservation Act," has been reintroduced in the 96th Congress as S. 885 and H.R. 3508. This legislation has been designed to address and solve the electric power problems confronting the Pacific Northwest. This proposed legislation was conceived on the basis of a general, although not universal, regional consensus. The proposed legislation was originally introduced in both houses of Congress by leading members of the Northwest congressional delegation, and was the subject of congressional hearings both in Washington, D.C., and across the region. As a result, numerous amendments were offered to improve it. The legislation was endorsed in principle, although by no means in every detail, by the national administration. It was not, however, an administration or BPA bill.

Another legislative proposal was put forward by Representative James Weaver of Oregon's Fourth Congressional District. His bill, the "Northwest Renewable Resources, Conservation, and Energy Planning Act" (H.R. 4159), proposes alternative mechanisms for resolving regional power issues.

Neither BPA nor any other executive branch agency can properly conjecture on the final outcome of a proposal before Congress which is not an administration proposal and the enactment of which is speculative and prospective. On the other hand, it would be disingenuous to ignore proposed legislation and, by implication, pretend that it does not exist. It is much too important. And it is not at all implausible to assume that it or a variant thereof might sooner or later be enacted.

The formulation of a BPA proposal was additionally influenced by many comments on the Draft Role EIS which urged selection of a proposal which was more specific-action oriented and with more emphasis on energy conservation than had appeared in the original draft. In view of these circumstances and in response to such comments, a number of selection criteria were established, to wit:

1. The BPA proposal should conform with executive agency protocol; hence, it should not depend on the speculative outcome of any pending legislation not proposed by BPA or the national administration.

2. The BPA proposal should be based essentially on the exercise of existing legislative authority, a known and available quantity.

3. The BPA proposal should be identified with more precision and more detail, without ambiguity.

4. The BPA proposal should be realistic; it should represent a plausible outcome.

5. The BPA proposal should have been encompassed within the original Draft Role EIS, the predecessor to this document.

6. Within existing legislative authority and to the extent possible, BPA should adopt policies that will support the goal of planning and operating the regional power system under the one-utility concept.

7. The BPA proposal should include a vigorous energy conservation policy that is realistic and feasible under existing legislative authority.

8. In recognition of the dynamic setting within which future regional power plans and programs must be executed, the BPA proposal should allow for endorsement in principle of additional prospective legislative authority that would (1) reinforce and strengthen the likelihood of achieving the goal of planning and operating under the one-utility concept, (2) provide additional tools to achieve regional electric energy conservation, and (3) respect existing broad institutional arrangements and political realities.

In the absence of selection criteria, any number of alternatives might be regarded as candidates for the BPA proposal. The range extends from one extreme in which new Federal legislation would be enacted to significantly reduce BPA's role in the region to another extreme in which new Federal legislation would create a regional power authority involving large-scale alterations in existing institutional arrangements. Within these two extremes are an almost infinite array of possibilities, the two most realistic and likely of which are (1) energetic utilization of existing legislative authority, and (2) new legislative authority along the lines of proposed legislation introduced in the 95th Congress. It is the former of these two alternatives that has been selected as the BPA proposal, with an added feature allowing for endorsement of additional legislative authority that would further improve attainment of the one-utility concept and energy conservation objectives.

The most compelling reason for selection of existing legislative authority as the framework within which the BPA proposal should be structured is that it is a known and currently available quantity, a course of action that can be implemented with a high degree of certainty. Power planning decisions in the region await resolution. Time marches on. Congress may or may not act on proposals for new legislation. The potential for serious power shortages looms on the horizon. Uncertainties about the future allocation of Federal power resources interfere with planning efforts. Lawsuits are pending. A kind of paralysis and malaise has overtaken the decisionmaking process. However effective some legislative proposals might be in overcoming the region's power planning problems, what proposed legislation might ultimately look like or when, if ever, it would be enacted, cannot be accurately predicted.

In this setting of large uncertainties it is better to develop an optimum program within a known framework (existing authority) than to do nothing at all or to rely on abstractions and speculations which may or may not materialize. The BPA proposal is straightforward and simple: proceed expeditiously to do the best that can be done under existing authority to solve the region's energy problems. If, after such a proposal is adopted and implemented, something conceptually and functionally superior is provided by way of new Federal legislative authority, BPA and the Northwest can be expected to take full advantage of its provisions. If, on the other hand, BPA and the region are left with no more legislative authority than at present, at least the best will be made of the circumstances.

In the meantime, this Final Role EIS does not ignore the alternative of regional power legislation. First, as has been stated, the BPA existing authority proposal allows for endorsement in principle of new complementary authority. Second, to be as forthright as possible and to provide the public and decisionmakers with a full understanding of the implications and potentials encompassed by the proposed legislation, that alternative will also be described (as a "preferred" or "ranking" ancillary candidate), along with three other alternatives, in the main body of this Final Role EIS (i.e., in terms of actions and impacts). The key features of that ranking alternative will also be arrayed in this overview alongside the features of the BPA proposal. Thus, a side-by-side analysis of the two most likely or realistic choices will be facilitated.

THE BPA PROPOSAL: KEY ELEMENTS

The BPA proposal is predicated on several key assumptions:

1. BPA will operate under its existing legislative authority.

2. BPA rates will be set at a level that will fully recover all costs of operating and constructing the Federal Columbia River Power System (FCRPS) including the costs of acquired power and timely repayments of the Federal investment, plus interest.

3. To the extent feasible within existing authority, BPA will implement new programs and/or modify existing programs that are calculated to move closer towards achievement of the one-utility concept.

4. Within existing authority, BPA will expand its energy conservation program and its public involvement program as much as it appropriately and feasibly can.

5. The high level of interutility cooperation that has been forged by power entities in the Pacific Northwest will be maintained.

6. BPA will endorse, in principle, proposals that enhance the prospect of achieving the one-utility concept, including additional authority for implementation of regional energy conservation programs.

7. BPA will continue in its role as coordinator for interregional transmission expansion opportunities.

The BPA proposal can be conveniently described in terms of eight areas of activity: (1) customer services, (2) transmission planning and services, (3) power planning, (4) conservation, (5) sources of power, (6) sales, (7) rates, and (8) public involvement. It is described in detail in Chapter III of this Final Role EIS.

With respect to (1) customer services, upon request BPA will continue to integrate new and existing non-Federal generating resources into the FCRPS in order to facilitate regional coordination of generation and transmission. All BPA costs would be borne by the beneficiaries of its services. The specific customer services that BPA would offer would include load factoring, forced outage reserves, load growth reserves, trust agent functions, resource information clearinghouse services, and miscellaneous services.

With respect to (2) transmission planning and services, BPA would continue to plan, build, and operate its transmission system in coordination with the region's utilities to reflect the one-utility concept. BPA would continue to provide transmission services such as wheeling non-Federal power, transmission of excess non-Federal generation capacity over existing lines, short-term transfers of nonfirm energy and capacity if and when sufficient transmission capacity is available, and point-to-point transfer of power over its facilities when excess transmission capacity is available.

With respect to (3) power planning, BPA would make maximum use of existing authorities in implementing, coordinating, and facilitating regional power planning to ensure optimum economic efficiency in the design and operation of the regional power system. Power planning functions would include development of planning assumptions, load forecasting, preparation of an annual power planning document, identification of resource sites, and cooperative activities.

With respect to (4) conservation, BPA would proceed with conservation efforts making maximum use of present authority while also being mindful that new legislation might allow for enlarged efforts to achieve greater conservation results. BPA would follow a policy designed to achieve as much cost-effective and feasible regional electric energy conservation savings as is practicable. That policy is described in greater detail in the main body of this EIS.

With respect to (5) sources of power, BPA would not acquire any significant amounts of new non-Federal resource capability beyond that provided for under existing agreements but would continue to offer FCRPS services to integrate new regional resources into the system. BPA would encourage development of cost-effective and feasible renewable resources including additional hydro and unconventional resources, and would play an expanded role in the investigation and assimilation into the power system of such resources.

With respect to (6) sales, preference and priority for public bodies and cooperatives would continue. As existing power sales contracts expire, BPA would have to reallocate its limited power supplies in a fashion that accords with existing legislation. A proposed BPA power allocation policy was announced in 1979. Regional power legislation would likely obviate the need for reallocation.

With respect to (7) rates, new wholesale power rates were made effective December 20, 1979, satisfying BPA's legal obligation to produce sufficient revenue to recover all of the costs of producing and transmitting power including timely repayment of the Federal investment in the FCRPS plus interest, and of making BPA power available at the lowest possible cost consistent with sound business principles.

With respect to (8) public involvement, BPA would maintain and, where feasible, expand public participation in its policy formulations and in regional power planning in terms of formal requirements such as notice, review, and comment, and in terms of other nonrequired procedures such as workshops, mailings, public meetings, hearings, and other mechanisms that ensure that the public is given an adequate opportunity to consider proposals, express comments, and have those comments carefully considered.

In addition to the BPA proposal, there is assumed a consistent or complementary regional structure that would provide for the related activities of the non-Federal sector of the Northwest regional power system. Although BPA would assist in the integration of new resources into the regional power system, many utilities would be responsible for their own load forecasting and resource acquisition. Presumably, as BPA power allocations become insufficient, existing and new preference customer utilities would seek new energy resources of their own. Investor-owned utilities would also be responsible for meeting load growth on their systems through conservation or other resources. BPA direct-service industrial customers would have no assured long-term power supply upon expiration of their present contracts with BPA; what those firms might elect to do as a result is conjectural.

The responsibilities of State and local governments for energy facilities siting would remain unchanged as would the regulatory authorities of State agencies except as modified, if at all, by new State laws or as required by new Federal legislation.

The regional complement assumes continuation of the cooperative agreements (e.g., the Northwest Power Pool, the Pacific Northwest Coordination Agreement, the Columbia River Treaty, etc.), assumes there will be incentives for utilities to enter into multiparty construction agreements to capture economies of scale and other benefits, and assumes that the Pacific Northwest Utilities Conference Committee or some similar entity comprised of regional utilities would continue to participate in identifying the need for and characteristics of proposed regional resources.

ALTERNATIVES

In addition to the BPA proposal, this Final Role EIS identifies four alternatives. The BPA proposal and all four of the alternatives are described in detail in Chapter III of this document. The key elements of three of those alternatives--Alternatives 1, 2, and 4--are strictly described here. Because Alternative 3 has received much more intensive and widespread attention than any of the other three, it is deemed the ranking alternative and is treated separately in the next section of this overview to facilitate a side-by-side comparison to the BPA proposal.

Alternative 1--Legislation Reducing BPA's Role in the Region. Under this alternative, BPA's existing authority, particularly with respect to transmission construction, would be significantly reduced through repeal of portions of the Federal Columbia River Transmission System Act of 1974. Under such use restrictions, the Federal transmission system would not be available to facilitate regional planning involving non-Federal power. Except for Federal projects, BPA would have no responsibility to provide additions to the Federal transmission system. The regional structure depicted is one where resources and transmission needs within the region are resolved through independent effort by diverse utility interests.

Alternative 2--Existing Authority; BPA's Role Declines Relative to the Region. Under this alternative, no new legislation, either reducing or expanding BPA's operations, is considered and no dynamic change from past practices is contemplated. Differing from Alternative 1, this alternative would allow for BPA construction of additions to the Federal transmission system as needed to integrate some non-Federal generation. But, because of BPA's diminishing role over time in relation to the region as a whole, this alternative assumes the formation of one or more "mutual operating agencies" to supplement some collective services now provided by BPA, including transmission and scheduling.

Alternative 4--New Authority; Regional Energy Commission. Under this alternative, which is based upon elements of the Weaver Bill, a Regional Energy Commission with broad authority to determine regional energy policy would be established through legislation and, in cooperation with BPA and regional non-Federal utilities, would provide integration, pooling, and marketing of all the electric energy in the region. Under the direction of the Regional Energy Commission, BPA would become the energy wholesaler for the Pacific Northwest offering full requirements contracts to all utility and other participants in the region.

ALTERNATIVE 3: THE RANKING ALTERNATIVE

Regional power planning problems, described earlier, have been increasing in both abundance and severity. Those problems triggered development and presentation of several legislative proposals to Congress. Since the Federal Government plays such a large role in the scheme of things and since BPA is the Federal Government's power marketing agency in the Northwest, it is no surprise that all of the legislation that has been introduced would, if enacted, substantially impact BPA's role in the region.

Legislation entitled "The Pacific Northwest Electric Power Supply and Conservation Act" (S. 2080 and H.R. 9020), which was developed under the auspices of the Pacific Northwest Utilities Conference Committee (PNUCC) with the participation of BPA's direct-service industrial customers and others, was introduced in Congress in September 1977. Under this legislation, (1) a new regional utility organization with various power planning functions would have been established, (2) an energy conservation program with strong incentives would have been mandated, and (3) BPA would have had increased authority to purchase power from non-Federal powerplants and sell that power and Federal system power at three different rate levels. The legislation would have authorized but not obliged BPA to purchase and then supply the future power requirements of all of the region's utilities and existing BPA direct-service industries requesting that service.

Legislation was also introduced in that session of Congress by Oregon's U.S. Representative Jim Weaver to create a "Columbia Basin Energy Commission" (H.R. 5862). The Commission would have determined regional electric energy policy, prepared load/resource forecasts, balanced electric energy demand and supplies, established BPA rates and terms for the acquisition, sale, and disposition of electric energy by BPA, and, in cooperation with BPA and non-Federal utilities, provided for generation and purchase, integration and pooling, and marketing of all Pacific Northwest electric energy. Within that context, BPA would have been responsible for implementing the Commission's decisions to acquire, pool, transmit, and market electric energy generated in the Pacific Northwest. The lowest cost BPA energy would have been made available for "use of the general public, domestic and rural," and for city, county, and State government uses. The remaining BPA energy would have been available to serve all other regional electric energy demands.

Many field hearings were held on these bills by both the U.S. Senate and House of Representatives. Those hearings showed that while the PNUCC proposal enjoyed support among most utilities and electroprocess industries, some utilities opposed its allocation provisions. Many nonutility interests also opposed the bill because of its power purchase provisions, anti-trust problems, and a perceived lack of emphasis on conservation and public involvement. The "Weaver Bill" was supported by many conservation and environmental groups, but it was opposed generally by the utility industry and by some nonutility interests due to its sweeping alterations in existing institutional arrangements. Neither of the bills was able to generate a consensus in the region.

The hearings did demonstrate, however, that regional power legislation was needed. Several points were made clear:

1. Failure to pass legislation expeditiously could trigger implementation of Oregon's Domestic and Rural Power Authority (DRPA) along with an almost certain prospect for paralyzing litigation to follow. However, the Oregon legislature has amended the legislation authorizing DRPA, postponing its effective date from March 1979 to March 1981.

2. Other lawsuits are already in process and, no matter what their outcome, they are almost certain to be appealed.

3. BPA will issue its proposal for the allocation of existing Federal power and, following consideration of public comments on the proposal, BPA will establish its final allocation policy in 1981; that policy may also be taken to court where it would probably be tied up in litigation beyond the expiration of the first direct-service industry contract in 1981 and the first preference utility contract in 1983.

4. The prospects of acrimony and dissension among the regional power interests are likely to increase the longer regional power supply issues remain unresolved.

5. In the meantime, an effective regional electric energy conservation program and resolution of the region's power supply problems would be impeded.

Accordingly, consensus began growing among the region's utilities, States, and political leaders regarding the need for legislative changes that would appropriately broaden BPA's role in the region while retaining a diversity in the ownership and management of the region's power system and ensure appropriate local, State, and regional controls, as well as congressional oversight. As a result of hearings in the 95th Congress, Northwest congressional leaders drafted and introduced legislation in Congress in August 1978. The proposed legislation was entitled "Pacific Northwest Electric Power Planning and Conservation Act" (S. 3418 and H.R. 13931). That legislative proposal attempted to be responsive to national energy policy, as well as to the diverse electric power and State and local governmental interests of the region. In the spring of 1979, every member of the congressional delegation from Oregon, Washington, and Idaho, except Representative James Weaver, of Oregon's Fourth Congressional District, sponsored and reintroduced this same legislation as S. 885 and H.R. 3508. This version passed the Senate on August 3, 1979. Representative Weaver introduced an alternative bill, "Northwest Renewable Resources, Conservation, and Energy Planning Act" (H.R. 4159), which also proposed mechanisms for regional power planning.

Elements of the Ranking Alternative

The ranking alternative was developed on the basis of guiding principles very similar to those set forth earlier in this overview. It is based on the legislation as originally introduced in Congress in August 1978, modified to reflect suggested amendments for improvement which repeatedly surfaced in subsequent congressional hearings held in Washington, D.C., and in the region. Among the most significant provisions of the ranking alternative are the following:

1. Power Planning. A regional power planning and conservation program would be developed and would include regional load/resource forecasts, proposed conservation programs, model wholesale and retail rate structures to encourage conservation, proposed renewable, waste heat, cogeneration, and other resource acquisitions, proposed reserves, and major transmission system additions.

2. Regional and Public Participation. A permanent Bonneville Consumers Council, to be appointed by the governors of the Northwest States, would be established. Half the members would be elected local government officials. A permanent Bonneville Utilities Council would be established, consisting of representatives elected by the region's utilities and the direct-service industrial customers. BPA would establish comprehensive public participation programs. The regional power planning and conservation program would be developed in consultation with the Northwest governors, the Consumers and Utilities Councils, BPA customers, and the general public. If there were significant disapproval, the issues would be sent to Congress for resolution. In any event, congressional approval would be required for all major resources acquisitions each of which would be included in BPA's annual budget submittal to Congress.

3. Resource Acquisition Process. All proposed major resource acquisitions would undergo review by the public at large, the Northwest governors, and the Consumers and Utilities Councils, and each would be submitted with the views of the governors and the Councils to the Congress, together with evidence of compliance with the National Environmental Policy Act of 1969.

4. Conservation. Before BPA could acquire new electric energy resources, action would have to be taken to implement all feasible, cost-effective conservation. BPA would also be obliged to encourage energy conservation among regional consumers by providing technical or financial assistance, cooperating with utilities and governmental authorities to promote voluntary conservation, and aiding State and local governments in devising conservation mechanisms.

5. Renewable Resources. If conservation savings were inadequate to meet BPA's power obligations, BPA would be authorized to obtain energy from feasible, cost-effective energy sources, owned by other entities, which relied on renewable fuels, waste heat, or cogeneration.

6. Conventional Resource Acquisitions. To the extent that conservation savings and renewable resources were determined to be insufficient to meet BPA's power obligations, BPA would be authorized to acquire the output of conventional generating facilities, with priority given to resources with high fuel efficiency. BPA would not be authorized to construct or own any generating resources except, as a last resort, small facilities to assure transmission system reliability.

7. Preference Clause. Preference and priority for public bodies and cooperatives in the sale of Federal power would be preserved intact.

8. Power Sales. BPA would meet the needs of its preference customers and, subject to availability of power and the preference clause, the requirements of investor-owned utilities, too. Preference customers and, after 5 years during which rates would be progressively decreased, the residential and small irrigation or farm loads of investor-owned utilities, would be supplied at BPA's lowest rate. Participation by utilities would be voluntary. BPA would also be able to sign long-term, power sales contracts with direct-service industrial customers, but at substantially higher rates than those customers are currently charged.

9. Rates. BPA would continue setting rates to recover all of the costs associated with acquisition, conservation, and transmission of electric power, including timely repayment of the Federal investment in the Federal Columbia River Power System, with interest. BPA rate proposals would have to be confirmed and approved by the Federal Energy Regulatory Commission.

10. Financing. The Federal Columbia River Transmission System Act would be amended to permit BPA to issue and sell bonds to the U.S. Treasury at prevailing market interest rates, not only for transmission construction, as at present, but also to help finance implementation of proposed conservation measures and research and development of unproven resources that hold promise for ultimate application within the region.

11. States' Jurisdiction. The rights of States to determine retail electric rates (except that retail rates charged residential and small irrigation customers of investor-owned utilities would have to reflect lowest rate for BPA power available to those utilities for that purpose) and the rights of States to make energy facility siting decisions would not be abridged or diminished.

The attractiveness of this particular alternative is that it would (1) meet important national energy policy goals, especially maximum use of all feasible, cost-effective conservation as a resource to reduce regional needs for additional generation, (2) assure maximum use of cost-effective and feasible renewable resources, (3) maintain the diversity of electric power ownerships in the Northwest, (4) solve regional power planning problems which have infected the region with huge uncertainties and the potential for serious power shortages, and

(5) provide State and local governments, diverse interest groups, rate-payers, and the public at large with genuine and effective opportunities to help shape the power planning program of the region.

CONCLUSION

This final environmental impact statement examines the Pacific Northwest electric energy system and BPA's role in that system. That examination includes an inspection of the activities of other enterprises in the region with respect to BPA's program and, more specifically, with respect to BPA's capabilities in power acquisition, management, transmission, and marketing of electric energy.

Over the years, BPA's relationships with other Pacific Northwest entities have been changing and evolving. It is a dynamic process which affects BPA's acquisition, marketing, and transmission capabilities and responsibilities. Among other things, these changes have reflected an evolving body of statutory authority, and the varied philosophies of the political administrations under which BPA functioned and of the eight Administrators who have been appointed to lead it from its establishment in 1937 to the present.

Whatever BPA's future role--whether as an aggressive leader or passive participant--it will result in actions and reactions of others. Perhaps the Federal District Court, in its 1977 opinion, was identifying this relationship when it directed BPA to prepare an EIS "concerning Phase 2 of the Hydro-Thermal Power Program" or any similar program entered into subsequent to Phase 1. The court's opinion characterized BPA as the "linchpin" of the Northwest's electric energy industry. Accepting that BPA's presence, by virtue of its size, makes it a prominent element in the electric energy planning process in the Pacific Northwest, and accepting further that BPA has a program which involves other energy entities in the region, its "linchpin" designation may be appropriate. BPA has written this EIS to describe the elements and assess the impacts of: (1) the regional electric energy system and what BPA does in that system, and (2) a range of BPA and regional alternatives that might begin to resolve a number of electric energy problems in the Pacific Northwest. Included in this examination are the actions and reactions of other entities within the region, and the actions and reactions of the region as a whole to BPA as the major carrier of electric energy and as the wholesale marketing agent for power produced by the FCRPS.

BPA intends, by this Final Role EIS, to have as fully explored its present program and capabilities, a range of realistic alternatives thereto, impacts, and regional actions and reactions, as is feasible and practicable at this time. Many reviewers commenting on the original Draft Role EIS complained of its complexity. Unfortunately, the relationships which are examined in this Role EIS are complex. Consequently, the EIS itself is complex. In reducing the size of this Final Role EIS, BPA has attempted to present a comprehensive but manageable analysis of its basic functions, now and as they may be in the future. This Final Role EIS also examines the environmental impacts of those functions and the environmental impacts associated with others' responses so that the readers, and, of course, decisionmakers, may understand the broad programmatic implications and consequences of decisions.

This Final Role EIS analyzes impacts of all existing facilities and those that had been scheduled for installation under Phase 2 of the Hydro-Thermal Power Program. Beyond that, it analyzes broader generic or generalized impacts which can be inferred from the five alternative packages (the BPA proposal plus four alternatives) comprising optional levels of regional cooperation and coordination. The impacts of the alternative levels of cooperation include those of potential resources which could be developed. Because the region's resource selections for the next 20 years cannot be predicted with confidence, resource impacts are addressed in the context of hypothetical "worst-case" situations with respect to adverse environmental impacts. This approach is consistent with the regulations of the Council on Environmental Quality for implementing the National Environmental Policy Act. As greater detail becomes available regarding potential resources, and as more specific proposals for power resource development are formulated, the impacts of future resources will become more precisely known, and a "worst-case" approach may be unnecessary. In summary, this EIS is a policy or program level of analysis; site specific studies for project-level proposals will provide detail to the general discussions presented in this EIS.

Chapter II

AFFECTED ENVIRONMENT

II. Affected Environment.

This chapter gives a brief description of the environment of the region, highlighting those aspects which are most likely to be affected by BPA's current functions and its proposal to make optimal use of its existing authority in pursuing regional coordination.

A. Physical Environment.

The geographical region described in this chapter includes the States of Washington, Oregon, Idaho, the portion of Montana west of the Continental Divide, and the coal resource areas in Montana and Wyoming. As shown in Figure II-1, the region may be divided according to environmental similarity into seven subregions; including the Puget Sound-Willamette Valley, the Columbia River Plateau, the Snake River Plateau, and the Great Plains, which are separated respectively by the Coast Range, the Cascades, and the Rocky Mountains. Numerous streams, many of which feed into the Snake and Columbia rivers, offer abundant opportunities for transportation, irrigation, commercial fishing, recreation, and the production of electricity.

Most of the region enjoys a mild climate; cool, moist, Pacific air masses carried eastward by the winds dominate the climate of the area west of the Rockies. The lush, green area west of the Cascades is characteristically mild and wet year-round. The area east of the Cascades typically receives no more than 15 inches of precipitation annually and is subject to more seasonal variation in temperature. In both areas there is much less precipitation during the summer. East of the Rockies, the climate is influenced by cold, dry, Arctic air masses and warm, moist air from the Gulf of Mexico. Seasonal temperature differences on the Great Plains are greater and precipitation is more unevenly distributed throughout the year than in the areas to the west. Generally, the region is relatively free from violent weather or other natural hazards (except for the occasional eruption of usually dormant volcanoes). The region experiences moderate earthquake activity with the risk of greatest damage in the areas of Puget Sound, eastern Idaho, and southwestern Montana. A number of mountains in the Cascades have a volcanic origin and, with the notable exception of Mt. St. Helens, have been relatively quiescent during their recorded history.

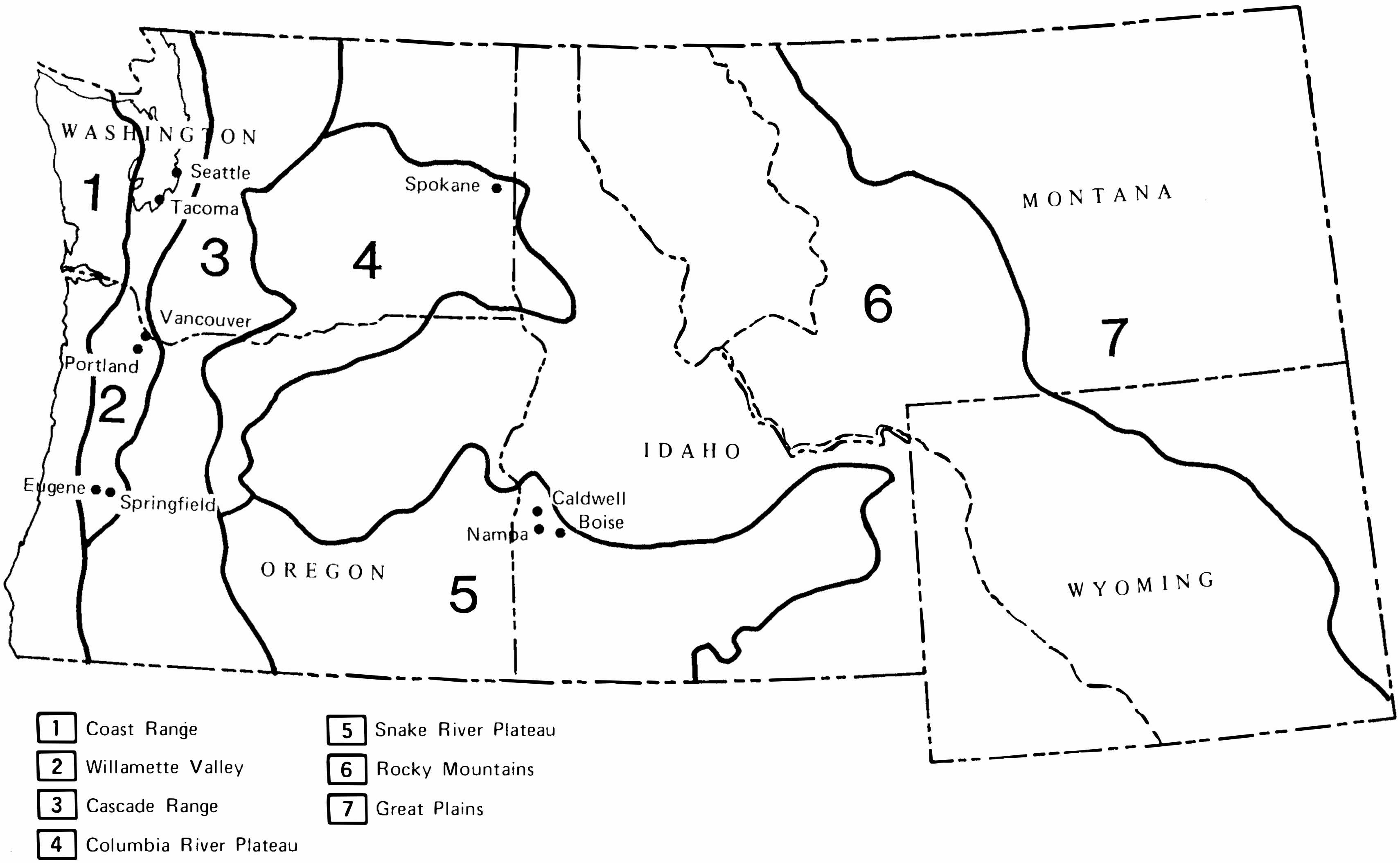
B. Land Use and Ownership.

Half of the region is covered by forest. The climate in that part of the region west of the Cascade Range is particularly well suited to the growth of trees, and three-quarters of the land in that area is covered by forest, compared to less than one-third of the land east of the Cascades.

Range and agricultural land covers the next largest area in the region. Rangeland occupies substantial areas in the Snake River and Rocky Mountain subregions. Agricultural lands are located primarily on the Columbia River Plateau, along the Snake River, and in the Willamette Valley.

Figure 11-1

SUBREGIONS AND MAJOR CITIES



The major urban centers are Seattle-Tacoma, Portland-Vancouver, Eugene-Springfield, Spokane, and Boise-Nampa-Caldwell.

About two-thirds of the region is publicly owned and managed, enabling the development of effective land management programs and extensive recreational opportunities. The Federal Government owns half of the region's land, including about two-thirds of the land in western Montana and Idaho, one-half of the land in Oregon, and less than one-third of Washington. The U.S. Forest Service and Bureau of Land Management control most of the Federal land and manage much of the region's forest and range land. Smaller areas of Federal land are managed by Bureau of Indian Affairs, with 29 Indian reservations; the Water and Power Resources Service; and the National Park Service, including 6 national parks. State and local governments own about one-sixth of the land in the region, leaving one-third of the total area under private ownership.

C. The Regional Economy.

Of the total population of about 6-1/2 million, almost 2-1/2 million are employed. During the past two decades, population growth rates in the region have exceeded the national average, with Oregon and Washington experiencing more growth than the rest of the region. Because of the cyclical nature of the region's economy, unemployment rates have nearly always been higher in the region than in the Nation as a whole during the last 20 years. Within the region, Idaho has generally had the lowest rate of unemployment, while western Montana has had the highest, except during the early 1970's when the recession in Washington's aircraft industry resulted in high unemployment in that State.

About two-thirds of the region's labor force is employed in the areas of retail and wholesale trade, services, government, and transportation. The latter has been particularly important in the region's economy and includes a largely completed interstate highway system, coastal and inland water traffic, railroad lines from the regional centers to the major ports, and air transportation between the major cities.

One-fourth of the labor force in the region, but somewhat less in Idaho, is employed in manufacturing and construction. Throughout the region, two of the three largest manufacturing employers are the lumber and wood products industry and the food and kindred products industry. In addition to these two industries, the third large manufacturing employer in Washington is the transportation equipment industry; in Oregon, the electrical equipment and supplies industry; and in Idaho, the chemicals and allied products industry. An important factor in the growth of some industries in the region, particularly chemicals and primary metals, has been the availability of inexpensive electricity.

The remainder of the labor force is employed in agriculture, forestry, commercial fishing, and mining. While the percentage of workers in agriculture is twice as high in Idaho as it is in the rest of the region, the State with the highest percentage of land in agriculture is Washington. Throughout the region, the construction of new irrigation facilities is bringing more land into production. Forestry, fishing, and mining occupy a much smaller percentage of the labor force than does agriculture. Commercial fishing takes place along the coast and on the Columbia River. Most of the timber harvest occurs west of the Cascades. Mining is of greater importance to the economy in Idaho and the two coal resource areas in Montana and Wyoming than in the rest of the region.

D. Patterns of Electricity Use.

The use of electricity within the region may be described according to differences in geographical location and time of the year. The subregion of Puget Sound-Willamette Valley, where two-thirds of the region's population lives, uses the greater portion of the electricity consumed in the region. Within this subregion, electrical energy requirements are highest during the winter when space heating needs are greatest. East of the Cascades, electrical energy requirements tend to be highest during the summer because of irrigation pumping and air conditioning loads.

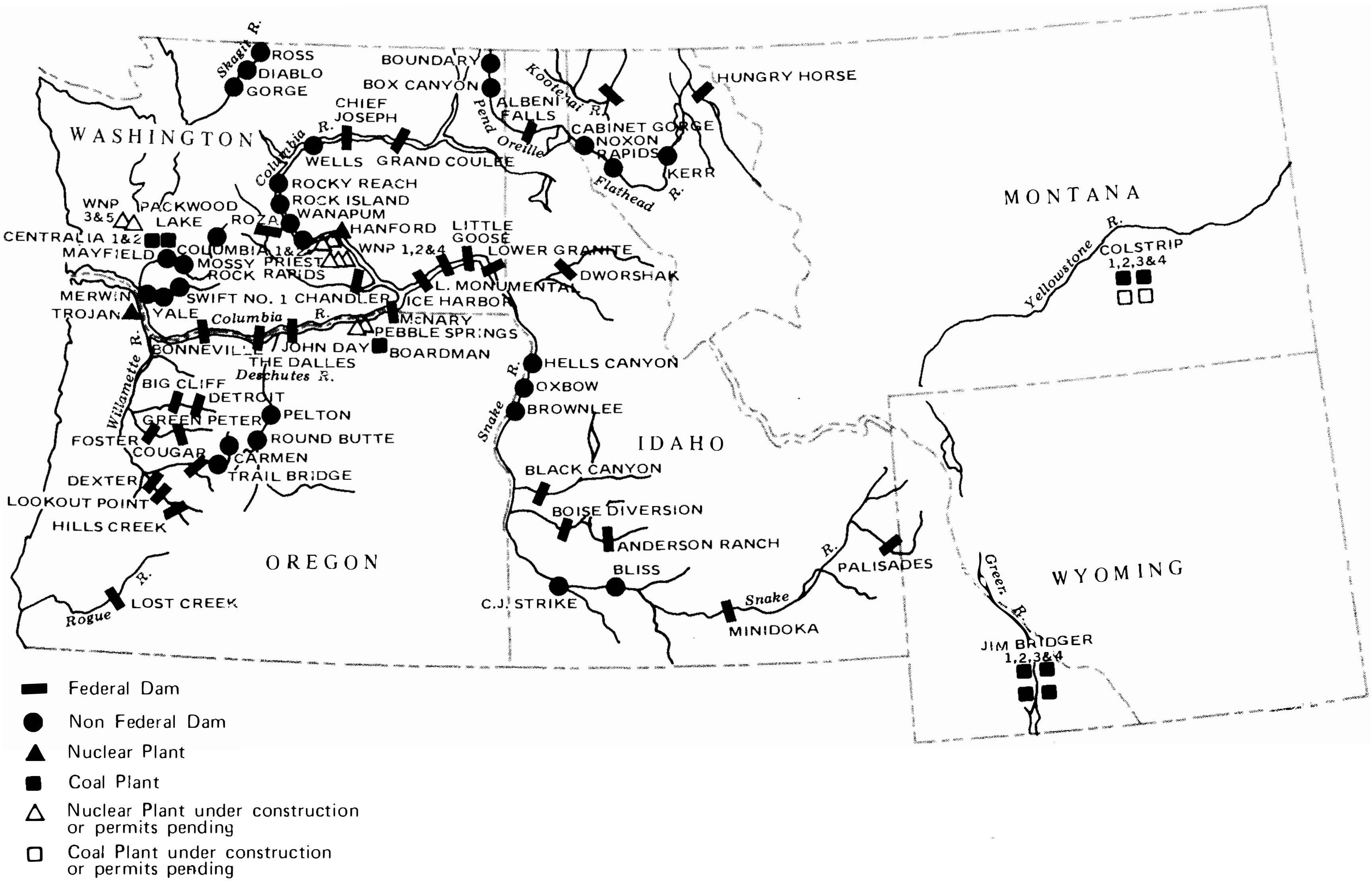
The use of electricity within the region may also be described according to the type of user. Almost half of the electricity consumption is industrial, with electroprocess industries purchasing one-half of the total industrial consumption. The next largest users are the forest products industry, which uses one-fifth of the industrial consumption; crop irrigators, which use one-sixteenth; and the chemical industry, which uses almost one-twentieth. Residential users account for nearly one-third of the region's consumption of electricity, and commercial users account for one-seventh. Because the region has very little indigenous gas or oil, but a large supply of inexpensive hydroelectricity, far more homes and businesses in this region rely on electricity for space heating than elsewhere in the country. Residential customers in the region use twice as much electricity at half the cost per kilowatthour as the national average, although total per capita consumption of energy for the region is equal to the national average.

E. Existing Facilities for the Generation and Bulk Transmission of Electricity.

One-third of the Nation's hydroelectric potential lies within the region; the most desirable sites already have been developed. There are 58 major hydroelectric dams in the region as shown in Figure II-2. The 30 Federally owned dams produce about half of the electricity consumed in the region. Electricity is also produced at two nuclear plants (one Federally owned, one non-Federal) and seven non-Federal coal plants. In addition, there are nine nuclear plants and four coal plants under construction or with permits pending.

FIGURE II–2

MAJOR HYDROELECTRIC DAMS AND THERMAL PLANTS



Approximately three-fourths of the region's bulk high-voltage transmission system is owned and managed by BPA. The BPA system, shown in Figure IV-3, has links with transmission lines in two other regions, the Pacific Southwest and British Columbia, allowing for exchanges and sales of power.

F. Service Areas.

Consumers of electricity in the region are served by both publicly owned and investor-owned utilities. Rural areas are typically served by publicly or cooperatively-owned utilities, while other areas, with the exception of several metropolitan districts, are served by investor-owned utilities. Publicly-owned utilities sell a greater proportion of electricity in Washington than in the rest of the region. Within the region, BPA provides direct service to 15 industries and 6 Federal agencies, and it wholesales firm power to 116 publicly or cooperatively owned utilities and nonfirm power to 8 investor-owned utilities.

CHAPTER III

PROPOSAL & ALTERNATIVES

III. Proposal and Alternatives

A. Introduction

This section of the statement presents BPA's proposal and four alternatives. Each of these is divided into two major sections, the first presenting a description of how BPA would operate and the second describing how pertinent regional institutions, including BPA, would interrelate. The proposal and alternatives are each further divided into similarly titled subsections to facilitate comparison. A matrix display of the salient characteristics of each alternative, by subsection, is shown in Table III-1.

As demonstrated in the matrix, the proposal and alternatives can be ordered to reflect increasing levels of BPA responsibility for regional electric energy supply. The lowest level of BPA responsibility is described in Alternative 1, which assumes legislation reducing BPA's current role. Alternative 2 assumes no change in existing legislation, but, as a result of the actions of other regional entities and the exercise of administrative discretion on the part of the BPA Administrator, BPA's role in the region does not develop to match changing regional needs. This is the "no action alternative" in that no new legislation is assumed and BPA's role remains static in relation to other regional entities. The next level of BPA regional responsibility is described in the BPA proposal, which depicts BPA efforts to further regional power coordination within the limits of its existing legislation. Alternatives 3 and 4 both assume the passage of legislation expanding BPA's regional responsibilities, Alternative 3 by expanding certain BPA authorities within the context of existing regional institutions and Alternative 4 by creating a regional commission with wide regional power authorities to be exercised through the instrumentality of BPA.

A significant conclusion underlying the array of alternatives presented is that there is no realistic alternative to the one-utility concept for meeting future power needs in the PNW. As a practical matter, there can only be variations in the application of the one-utility concept. Regardless of the exact nature of future power programs in the PNW, they will all depend upon the coordinated operation of the existing hydro system and its use as a backup. Further, the existence of an extensive and interconnected main grid transmission system precludes any real alternative to the one-utility concept. For these reasons the proposal and alternatives represent the full range of institutional possibilities.

The proposal and alternatives do not include Phase 2 of the Hydro-Thermal Power Program (HTPP-2) as a specific alternative. The HTPP is discussed beginning on page I-16 in the overview; the material presented there will not be repeated here. However, the reviewer will recall that, as described in the overview, Judge Skopil did direct the preparation of an EIS on Phase 2 of the HTPP "or equivalent or substitute arrangements subsequent to Phase 1 of HTPP." The proposal is BPA's choice of a substitute arrangement to follow Phase 1 in place of Phase 2. Phase 2 of HTPP was not included as an alternative because it has been abandoned as a coherent, all-embracing concept. In other words, although HTPP-2 as a program had a beginning and an end, the concept behind the program continues. This concept, i.e., a centralized, one-utility approach, is seen as the basis for "substitute or equivalent arrangements" and is, therefore, the focus of this Final EIS.

Phase 2 was initiated in a time of minimum power sufficiency, when a potential shortage was imminent; Phase 2 was intended to provide a vehicle to eliminate the power shortage and provide funding mechanisms to meet increased costs. When Phase 2 was interrupted by litigation, and thereafter stopped by the injunction of Judge Skopil, agreement was rendered virtually impossible, because until the injunction was lifted no agreements would be possible and by that time other events, such as pending legislation, would make Phase 2 even less likely to be carried out. Claims of new preference customers to BPA power, arising during or after these events, would by themselves have been sufficient to prevent execution of the proposed Phase 2 contracts. BPA's notices of insufficiency, issued in June 1976, advising the preference customers that BPA could not meet the load growth requirements of such preference customers, marked the end of any voluntary agreement by BPA to enter into new contracts for the sale of energy to anyone except a preference customer.

Despite the conclusions above, it would still have been possible to have identified Phase 2 of HTPP as an alternative in this document. BPA considered this possibility, but rejected it because the essential elements which went into Phase 2 of HTPP were fully developed in the Role EIS as a part of the analysis of the proposal and alternatives and their associated impacts. For example, among one of the key HTPP-2 elements is the role of the DSIs (discussed in Chapter IV.A.2.e.). Other HTPP-2 aspects are BPA services and the function of the DSIs in providing reserves (Chapter IV.D.1.b.). Further, an HTPP-2 alternative seemed undesirable because Phase 2 was intended to provide only thermal plants and was not flexible enough to accommodate a resource shift to conservation or renewable resources.

The functions to be performed by BPA are analyzed in the proposal and alternatives, and BPA's role (excepting its power procurement role as an agent for its preference customers) as it was once identified in Phase 2 of the HTPP is not significantly different from the description of BPA's functions in the proposal. One difference is that BPA has no contractual basis for implementing restriction of the third quartile or any other quartile of the industrial firm power made available to the DSIs.

Construction of some of the plants identified as Phase 2 generation is proceeding as planned. Their progress continues without the support of a BPA agreement for DSI obligations as could have been expressed in the third quartile of industrial firm power contracts and without any obligation on the part of BPA to market such power. Integration of those plants by BPA is currently prohibited under the terms of the injunction of Judge Skopil in NRDC v. Hodel.

However, it needs to be emphasized that the most significant element of Phase 2 of HTPP, as identified by Judge Skopil, is the one-utility concept. This theme of varying degrees of centralization was the basis around which the Revised Draft Role EIS was constructed. Accordingly, the proposal and all the alternatives develop their respective functions and implementations in terms of alternative approaches to the one-utility concept. Therefore, the essential ingredient of Phase 2 of HTPP was fully examined. The voluntary cooperation among BPA, the DSIs, the preference customers, the IOUs and other elements of the electric energy picture in the Pacific Northwest are examined in the proposal and in Alternatives 1 and 2. The contractual nuances that were required in Phase 2 of HTPP were never fully developed, consequently, it would have been impossible to determine precisely how present voluntary cooperation might be changed or modified as a result of the final contractual arrangements required for Phase 2 of HTPP. Alternatives 3 and 4, providing greater affirmative action by BPA by statute, lie beyond the concepts contained in Phase 2 of HTPP. An essential new ingredient common to Alternatives 3 and 4 which was not present in Phase 2 of HTPP is the emphasis upon conservation and renewable resources as the first choices for supplying resources to meet load growth in the Pacific Northwest. These alternatives also anticipate that domestic and rural consumers throughout the region will have some share in BPA power. The use of the Federal system for equity in financing the entire energy supply program is far beyond Phase 2 of HTPP.

Although it is not presented as an alternative, the reviewer will find in Scenario E in Chapter IV.B.3., a presentation of the kinds of impacts that might have resulted from the continued development of a mixture of coal and nuclear generation which developed under the HTPP-2. By examining the comparison provided between this scenario and the other thermal and nonthermal scenarios in Chapter IV, the reviewer is presented a comparison of program alternatives including that represented by HTPP-2.

The other scenarios included in Chapter IV encompass the full range of impacts associated with future energy resource development. However, the actions specified under the proposal in this chapter, including the provision of services (wheeling, integration, load shaping) have little effect upon the ultimate regional composition or mix of future energy resources. As discussed in Chapter IV.D.1.b., the limitation affecting the influence of services on generation development stems from the fact that it is only one of a number of factors affecting the selection and location of generation.

BPA included in its original Draft Role EIS an "alternative scenario" prepared by the Natural Resources Defense Council (NRDC) in 1977. The thrust of the NRDC scenario was to achieve greater efficiency in energy use. To do this, NRDC suggested assistance programs, building and energy efficiency codes, and appliance efficiency standards. There were also suggestions that energy consumption should be directed to less energy-intensive consumers to reflect conservation policies. A further suggestion was for the creation of a separate entity having the responsibility for load forecasting, selecting resources to meet the region's energy needs, and siting of facilities. NRDC has revised their

TABLE III-1

COMPARISON OF BPA'S PROPOSAL AND ALTERNATIVES

BPA Functions	Alternative 1	Alternative 2	BPA Proposal	Alternative 3	Alternative 4
BPA Authority	New restrictive legislation affecting BPA's ability to construct regional transmission.	Continuation of existing authority.	Continuation of existing authority.	New legistlation expanding BPA's authority.	New legislation creating strong regional commission to run BPA.
Customer Services	Offer all current services as able over transmission system.	Perform all as currently except those provided by a mutual operating agency.	Offer all current services.	Offer all current services to expanded and varied resource base.	Offer to assume full public utility responsibility for regional loads.
Transmission Planning and Services	Maintain and increase capacity of existing grid to serve preference customers only.	Offer all current services not provided by a mutual operating agency.	Continuation of current policy.	Offer to provide all high-voltage transmission needed in regional program.	Construct or acquire all facilities needed to serve participants.
Planning	Perform only that needed for power allocations and to ensure reliability.	Perform only that which would affect BPA's programs and system.	Encourage and facilitate planning on regional scale.	Regional development of a regional power planning and conservation program.	Prepare forecasts for region and plan to meet all participants' requirements.
Conservation	In-house programs.	In-house and information "outreach" programs.	In-house, information, coordination and policy programs.	Invest in conservation as a resource of first priority.	Central, mandatory control over participants' conservation.
Sources of Power	No new long-term acquisition of non-Federal resource output.	No new long-term acquisition of non-Federal resource output.	No new long-term acquisition of non-Federal resource output.	Acquire output of resources necessary to meet customer load growth.	Keep regional energy supply and demand in balance through conservation resource acquisition or construction.
Sales	Single fixed allocation to existing preference customers.	Floating allocation to existing and new preference customers.	Reallocate to existing preference customers.	Offer to sell power to all regional utilities to meet their loads in excess of their committed resources.	Meet full requirements of all utilities who sell their entire resource output to the BPA pool and plan new resources to meet growth.
Rates	Continue present rate policy in establishing rates while considering standards set out in the Public Utility Regulatory Policies Act.	Continue present rate policy in establishing rates while considering standards set out in the Public Utility Regulatory Policies Act.	Continue present rate policy in establishing rates while considering standards set out in the Public Utility Regulatory Policies Act.	Continue present rate policy but with certain rates set by resource pool costs and other factors while considering standards set out in the Public Utility Regulatory Policies Act.	Continue present rate policy but establish two resource pools for calculating cost based rates while considering standards set out in the Public Utility Regulatory Policies Act.
Public Involvement	Meet minimal requirements of Section 501 of the DOE Act.	Continue present policy and procedures.	Enhance current policy and procedures through additional notices and meetings.	Expanded public participation and statutory procedures for consultation with region's governors and two new advisory councils.	Create a local governmental advisory committee, full public hearings, four of five commissioners appointed by governors.

Utilities	Individual or similarly situated utilities develop resources for their own requirements without coordinated regional planning.	A number of similarly situated utilities form a mutual operating agency to develop resources and transmit power.	Individual utilities or groups continue to develop own resources using regional planning coordination.	Individual utilities or groups develop resources for BPA acquistion when need evidenced in regional power planning and conservation program.	Participants retain energy distribution, resource operation, and billing responsibilities while BPA acquires or constructs resources.
State and Local Government	Rate setting and siting authorities unaffected.	Rate setting and siting authority unaffected but potential for coordination with mutual operating agency.	Rate setting and siting authority unaffected with earlier coordinative policy role in planning.	Rate setting and siting authority unaffected with early involvement in the development of the regional power planning and conservation program.	Rate setting and siting authority unaffected and policy coordination with regional coordination.
Cooperative Arrangements	Cooperative agreements difficult to implement because of less integrated regional transmission.	Cooperate through mutual operating agencies.	Continuation of current arrangements which evolve to accommodate regional needs.	Coordination through the regional power planning and conservation program and BPA acquisition.	Commission coordinates and supplies participants power requirements.

Alternative Scenario and a summary of the revised version has been included in Chapter IV.B.3.

In some respects, the revised Alternative Scenario resembles Scenario B of the "extreme case" resource scenarios presented in this EIS. Both the NRDC scenario and Scenario B are compilations of conservation and renewable resource potentials. The principal difference between the NRDC scenario and Scenario B is that the NRDC scenario is portrayed as an achievable development, whereas Scenario B and the other scenarios have been designed as improbable or extreme cases. This extreme case approach was utilized to overcome the uncertainties involved in predicting the impacts associated with the course of actual resource development. The scenarios are included with the assumption that the actual development of the regional power system will be less extreme in its reliance on particular technologies, and will have lesser impacts than presented in the scenarios.

Finally, it is important to note that BPA has recently proposed a policy regarding the allocation of Federal power to entities seeking BPA service. If adopted, this proposed allocation policy would not be implemented until July 1983. BPA plans to publish an analysis of its proposed allocation policy for public review and comment in late-1980. In addition to impacts to the physical environment, the policy analysis will include an examination of alternative allocation policies and their impact on system operations, power availability, and wholesale power costs.

B. Proposal

1. BPA's Proposal - Optimum Use of Existing Authority

a. General

The BPA proposal is based on certain assumptions regarding the continuation of current arrangements. These are: (1) that the cooperation among regional power entities would continue at its current level; and (2) that BPA would operate within its existing legislated authority.

The following description of BPA's proposal is divided into two parts. The first is a description of what BPA proposes to do within the regional context. The second part is a description of the regional power marketing functions and processes that have evolved since Phase 1 of the Hydro-Thermal Power Program. This second part depicts the regional structure within which BPA will operate in accordance with its proposal.

b. Customer Services

BPA would continue its policy of offering certain services, described below, to Pacific Northwest utilities to integrate their new and existing non-Federal generating resources into the Federal Columbia River Power System (FCRPS) for their use. BPA would also offer necessary services to direct-service industries to integrate contract purchases of replacement energy. Standards for the provision of services reflect prudent utility practice and BPA's participation in this area lies within the Administrator's informed discretion. BPA would offer these services to Northwest preference and nonpreference utilities and direct-service industries for resources constructed or energy purchased either within or outside the region in order to facilitate regional operation of generation and transmission. All costs associated with BPA's provision of services would be paid for by those receiving them either on a reimbursable basis, through exchanges, or through their wholesale rates for electricity. As loads and the number of generating resources and transmission lines in the region increase the volume of integrating services provided by BPA would be likely to increase, as well.

The services would be provided on a nondiscriminatory basis upon request of Pacific Northwest utilities and direct-service industries as long as resource operation, environmental, or other restraints do not preclude their sale. When BPA could no longer sell certain services to all applicants without decreasing the amount of energy available from Federal resources, those services would be allocated in accordance with any applicable BPA allocation policy. Where it would enhance the operation of the Federal generation and transmission system or where it would result in economic benefits to the system, however, these services would be provided to regional utilities on a nondiscriminatory basis under exchange agreements rather than under sales contracts.

Exchange agreements are contracts among two or more parties whereby they provide one another various services on an exchange basis rather than for payments in cash. Some exchange agreements may provide for establishment of energy accounts which may be settled monthly on the basis of net energy balances. In that event, the party in whose favor the balance exists is paid in cash or return of energy, or the balance is carried forward. This differs from a sales agreement, where one party disposes of a certain amount of energy or capacity for a fixed sum in cash.

Exchange agreements may provide for exchange of load factoring, transmission services, peaking capacity, or reserves. Exchange of firm power at one point on a utility's system for delivery of an equal quantity delivered at another point in the same hour, less transmission losses, is another form of exchange. There have also been exchanges of power with months or years between receipt and return.

The specific services that would be offered by BPA are listed below. For a more detailed discussion of the subject, see Draft Role EIS, Appendix C, pages II-53 to II-65. See also Part 2, pages VII-76 to VII-79.

(1) Load Factoring Services

BPA would continue to offer load factoring services to its customers. Load factoring is the function by which the output of a generating plant is "shaped" for delivery at times and in amounts that conform to a utility's load. Load factoring may be generally classified as either short-term or long-term. Short-term load factoring is required when a utility's resources are producing energy which is insufficient or in excess of that needed to meet the utility's hourly loads. Long-term load factoring is required when the generation from a utility's resources does not match its loads during certain months or seasons of the year. Load factoring is accomplished either by storing otherwise unusable energy in hydro reservoirs or by advance delivery of energy in exchange for the right to the generation of another resource at a later time.

(2) Forced Outage Reserves

BPA would continue to provide contracted amounts of capacity from the Federal system during hours when a utility had a generating unit which was unavailable, or was available at reduced capacity, due to a forced outage. A forced outage is an outage that results from emergency conditions requiring a component to be taken out of service. It can be an outage caused by equipment failure, natural occurrences, improper operation of equipment, human error, or various other causes. Capacity available to meet a forced outage is generally termed "forced outage reserves." The amount of forced outage reserves to be supplied may be determined by the forecasted frequency of forced outages of the units specified in service agreements or by the quantity of generation on forced outage. Contracts relating to delivery of forced outage reserves could include specific limitations as to the periods of availability and the generating units included. Forced outage reserves would continue to be provided consistent with the terms of the Pacific Northwest Coordination Agreement (see the Draft Role EIS, Appendix A, pages II-29 to II-31).

(3) Load Growth Reserves

BPA would offer load growth reserves to those customers who could not meet their power requirements due to unanticipated load growth. Unanticipated load growth is the difference between a utility's long-range forecast of its loads for a given year and the utility's forecast of its loads immediately prior to that year. Because generating resources take many years to plan and construct, utilities plan resources on the basis of long-range forecasts. As a result of unanticipated load growth, a utility may have insufficient operable resources to meet expected loads. The amounts of power BPA would be obligated to supply to meet such unanticipated load growth, referred to as load growth reserves, would be limited by contract. The total amount of load growth reserve capacity and energy BPA would plan to have available would be based on the number of utilities requesting this service, but, based on present analysis of need, would not exceed one-half of the region's average annual utility load growth. The maximum quantity of load growth reserves available from BPA would be adjusted from time to time to reflect improved accuracy in forecasting loads, slippage or advancement of resource development schedules, enhanced resource operations, and accelerated conservation implementation, among other factors.

BPA would either provide load growth reserves from Federal resources or could acquire the reserve power from regional utilities in exchange for other services. The charge for load growth reserves would reflect the cost of power reserved or acquired, if any.

Each utility would accept and pay for load growth reserves only if in advance of a contract year planning considerations indicated a need for it. Utilities could purchase load growth reserve energy and capacity in amounts limited to the smallest of: (1) the estimated firm energy or capacity deficit of the utility for the year as determined by BPA from data submitted by the utility; (2) the difference between the utility's previous load forecast for energy or capacity and its current load forecast for the year; (3) the average energy or capacity load growth of the utility in the previous 5 years; or (4) a pro-rata share of the load growth reserve energy or capacity BPA had available for the year.

(4) Energy Reserve

BPA would continue to maintain a reserve for new plant delay or plant inoperability. Currently, this reserve is held by BPA's direct-service industrial customers (DSI). That is, BPA makes use of this reserve by restricting deliveries to the DSI's in order to protect BPA's preference customer loads. It is now proposed that as each DSI contract expires, one-fourth of the expired contract demand be placed in a special category to be made available, with special restriction rights for BPA, to preference customers. (See proposed Allocation Policy).

(5) Trust Agent Power Purchases and Surplus Sales

BPA may act as an agent for utilities and industries in the purchase and sale of electric power and energy, whether from an existing or new source, thus balancing power surpluses and deficits.

On a short-term basis, BPA would act as a utility's agent in purchasing available energy from existing resources for a customer experiencing a deficit. Unless adverse impacts would occur on the Federal System this service could be combined with load factoring to ensure that the customer received the required power at the appropriate times. Conversely, when a customer had a surplus of energy available BPA could act as that customer's agent in arranging for a purchaser and also could wheel the power to the purchaser's system.

Short-term power purchases would be conducted under trust arrangements. The deficit customer would deposit sufficient funds to cover the cost of the power in a BPA trust account. BPA would endeavor to purchase the power from an existing resource and when it did so would pay the supplier from the trust funds and charge the customer the cost of BPA services such as wheeling, as well as the cost to BPA of its trust agent activities. BPA is not proposing to provide long-term trust agency services for the purchase or sale of the output of new plants.

c. Transmission Planning

Under the provisions of the Federal Columbia River Transmission System Act (16 U.S.C. 838d) the Administrator of BPA is required to "make available to all utilities on a fair and nondiscriminatory basis, any capacity in the Federal transmission system which he determines to be in excess of the capacity required to transmit electric power generated or acquired by the United States." Requiring availability on a "fair and nondiscriminatory basis" prevents the Administrator from being selective about either the kind or the location for generation to be added to the main transmission grid. Based on this authority the proposal provides that BPA would continue its current activities in planning, designing, and constructing the Federal Columbia River Transmission System (FCRTS). This policy would be a continuation of the "one-utility concept." Under this concept the total regional needs and resources are taken into consideration in developing alternative transmission facilities and determining the responsibility of BPA in the construction of new facilities. In addition to constructing transmission for Federal hydro plants and net-billed thermal projects, BPA would plan to provide transmission and substation facilities for integration of non-Federal thermal plants into the FCRTS, unless otherwise planned by plant owners. However, the provision of integrating services is subject to review of the Secretary of DOE to ensure that the transmission facilities to be constructed are "appropriate and required."

Under the proposal BPA would continue to construct and maintain a regional transmission system sufficient to provide all regionally required transmission or wheeling services to meet the region's requirements (e.g., firm wheeling, incidental energy, and use-of-facilities transmission). These services would be provided when requested by utilities. The cost for these services would be equitably recovered from Federal and non-Federal users. BPA would provide additional transmission services, such as transmission backup, as required to meet the transmission needs of the region.

BPA would continue to offer the following services:

(1) Firm Wheeling Arrangements

"Wheeling" refers to the transmission by BPA of large blocks of power for another party. It usually involves large utilities, major transmission facilities, and firm contracts for as long as 50 years. BPA proposes to continue to wheel non-Federal power.

Under wheeling agreements, specified amounts of power are made available to BPA at non-Federal generating plants and those amounts are delivered to the utility's system. Transmission losses are returned to BPA by the utility in the form of energy. Under this proposal these services would continue to be provided to those who need the use of BPA's main grid, BPA's secondary system, and BPA's portion of the Intertie. (See Draft Role EIS, Appendix B, pages IV-1 to IV-10.)

(2) Incidental Energy Transmission

BPA would continue to plan the transmission system based on the long-range needs of the region. This would allow utilities to use excess capacity for short-term transmission purposes. This short-term incidental energy transmission would be provided to utilities upon request. The charge for this service would be based on the transmission system average cost per kilowatthour plus losses resulting from the use of BPA's system. This service includes use of BPA's main grid and BPA's portion of the Intertie.

(3) Use-of-Facilities Transmission

BPA would continue to plan and construct facilities to be used jointly with its customers to serve their loads. Under this proposal, power would be delivered to a specific point on BPA's system and transmitted to the utility's point of delivery over the specific facilities involved. The charge for this service would be based on the annual cost per kilowatt capacity of the specific facilities being provided. BPA presently provides this transfer service to several publicly owned and investor-owned utilities, as well as ome industries.

When it would not be economically feasible for BPA to construct transmission facilities to serve its customers, BPA would enter into transfer agreements. Under this type of transfer agreement, a utility transmits BPA power on its its transmission system to a BPA customer. The utility transferring power for BPA is usually compensated in cash and for replacement losses.

d. Power Planning

BPA would make optimum use of its existing authorities in implementing and facilitating coordinated regional power planning. BPA would insure that its efforts would complement services performed by others within the region.

(1) Load Forecasting

BPA would assist and participate with utilities, States, and industries in the region in preparing a comprehensive regional load forecast. In the preparation of such a forecast, BPA would encourage the cooperation and participation of its customers, regional governmental authorities, and the public. The forecast would reflect the conservation efforts of BPA, regional utilities, and other regional entities; would be developed from a consistent data base; and would be prepared with a view to implementing, to the degree possible, the "one-utility concept" in regional power planning.

BPA would seek the aid and advice of regional entities in the development of a regional power use data base. It will utilize consistent assumptions, methods of data collection, and data categories, and will be used in the development of load estimates that, to the extent possible, will accurately reflect future regional energy demands.

The regional forecast would contain several important features. First, it would include the entire region: all of the States of Oregon, Washington, and Idaho, that part of Montana west of the Continental Divide, plus an area that extends 75 miles beyond the Columbia River basin which includes parts of Montana, Nevada, Utah, and Wyoming. This geographical area includes the PNUCC's West Group Area plus all of the service area of the Idaho Power Company, and parts of the service areas of the Montana Power Company, Utah Power & Light, and California-Pacific Utilities Company. Any utility within the region could decline to include its loads within the forecast. However, should BPA have responsibility for providing wheeling or other transmission capacity to deliver power to a utility's service area, that utility would have to provide to BPA, for its review, a load forecast covering its service area and other pertinent data.

BPA would publish the regional forecast in a detailed and understandable manner so as to be usable by utilities, States, and the general public. BPA would also provide computer time and staff for work on the forecast.

The forecast would designate loads by the end uses of electric power. This is necessary to identify the feasibility of implementing various conservation measures that could be directed at residential, commercial, industrial, and other end users. The resulting data would be available to State, regional, and Federal agencies for use in developing energy policies.

The regional load forecast would be closely tied to regional conservation programs. In order to accurately assess the potential for conservation, the characteristics of current and potential future uses of electricity would have to be known. For example, if studies revealed that installation of storm windows in existing homes was cost-effective, then the design of a conservation program would require knowledge of how many homes needed storm windows and how much energy might be saved by the installation of storm windows. The load forecast would, in turn, reflect the expected savings once conservation programs had been designed and implemented.

In summation, the regional forecast would cover the entire geographic region, be detailed and yet understandable, use the best available methodology and data, be broken down by appropriate end-use sectors, and reflect the savings expected from regional conservation programs.

BPA would not validate the load forecasts of regional utilities unless it was necessary for the proper execution of other BPA responsibilities in such areas as the application of an allocation policy, estimating reserves for unanticipated load growth, or rate setting. BPA also would not prepare forecasts for the individual utilities of the region, except at a utility's request. A utility must do forecasting for its own service area for several reasons, including revenue planning and distribution system planning.

BPA would continue to participate in preparing forecasts for those utilities not wishing or able to prepare their own and who so requested. Such forecasts would be developed on the basis of the particular characteristics of that utility's service area. Using the individual utility forecast as a base line, BPA could also perform such studies and analyses as a utility might request. (See the Draft

Role EIS, Part 1, pages IV-29 to IV-93 for description of current regional forecasting methods.)

(2) Power Planning Document

To encourage interutility coordination and cooperation, BPA would annually promote and participate in the development of a planning document which would address regional power problems and identify potential solutions. The document would include: an assessment of regional power problems; an analysis of possible solutions to identify the most effective, economical, and environmentally sound means of meeting these problems; proposals for BPA action within its existing authority which would mitigate or solve these problems; and proposals identifying regional cooperative actions which could be taken by utilities and States. This planning document would be based upon and include: the regional load forecast; BPA and regional conservation programs; resource development and operation plans and standards; information on BPA rate proposals and on the cost elements of other utilities' rates; and the service and transmission plans for the region.

BPA would compile this document from information supplied by regional utilities, State regulatory and energy authorities, and other regional government entities (e.g., State planning departments, local service districts, etc.) and would include any other information as may be available and appropriate. It would be distributed to participating entities and public bodies and to interested parties. The document would serve as a source document in the development of BPA power marketing policy.

(3) BPA Identification of Transmission Corridors

A transmission corridor is the route over which one or more transmission lines extend from one location to another. A transmission corridor may have multiple uses and be occupied by several utilities, such as railroads, pipelines, highways, telephone facilities, etc. Based on the annual load forecasts developed by the Pacific Northwest Utilities Conference Committee (PNUCC), BPA would identify each year the long-range transmission corridors required, taking into account the maximum use of existing corridor space. BPA would continue to cooperate with regional utilities to identify their generating sites and transmission plans. BPA would also cooperate with the appropriate Federal and State agencies to ensure compliance with land use requirements and to optimize transmission corridor use.

(4) Planning Assumptions

BPA would continue to employ its current planning assumptions in preparing its annual operating plan, and it is likely that the assumptions utilized in preparing the PNUCC load/resource forecasts would remain unchanged for the short-term future. These assumptions would continue to be reviewed, however, and at such time as changing conditions or policy considerations dictated, the assumptions would be replaced with ones more applicable to the changing composition or operation of the regional power system. Among the assumptions involved are those relating to resource availability, firm hydro energy capability, thermal capability, and necessary reserves. For a general discussion of PNUCC and BPA planning see the Draft Role EIS, Appendix A, pages II-3 to II-55, and especially pages II-6 to II-18. In addition and for purposes of information, a brief description of three key planning assumptions (reliability, critical water, and influence of existing grid) has been included as an attachment to this document.

(5) BPA Cooperative Activities

BPA would cooperate with existing State and Federal agencies, utilities inside and outside the Pacific Northwest and the public in planning its transmission and electric power system. BPA's cooperative effort would be accomplished through several existing interregional and regional organizations. Coordination of the development of the Federal Columbia River Power System would continue to be accomplished with the Pacific Northwest Utilities Conference Committee. BPA's involvement with interconnections and concern for developing consistant reliability standards would continue through its participation with several Pacific Northwest organizations, including the Northwest Power Pool and the Pacific Northwest Utilities Conference Committee (PNUCC). In addition to these Pacific Northwest organizations, BPA would cooperate with several interregional and national organizations including the National Electric Reliability Council (NERC) and through its participation in the Western System's Coordinating Council (WSCC). Coordination with Federal and State agencies would continue to be accomplished on an agency by agency basis. In order to assure consistent and economic power development and operation, several existing planning programs would continue. These programs include: (1) WSCC reliability standards; (2) FWSCC contingency and emergency planning; (3) Department of Energy and Electric Power Research Institute (EPRI) research and development efforts; (4) WSCC Annual "Significant Addition" documents; (5) WSCC "ten-year and beyond" plans; and (6) the PNUCC Long-Range Projection of Power Loads and Resources. These documents would be annually updated by the appropriate organizations.

BPA would continue to support, fund, and participate in research and development programs when those programs coincide with BPA's objectives. These include ways to reduce energy losses, minimize the impact of overhead transmission on the environment, new generation developments, and advanced power system operation. BPA's participation would be carried out through several organizations including appropriate Divisions in the Department of Energy and EPRI.

In cooperation with other regional utilities, BPA would continue to identify and adopt such planning and operating procedures as would assure economical and reliable regional power operations, and would promote the adoption of consistent standards by regional utilities and agencies. Such planning and procedures would include: (a) regional reliability standards (see Draft Role EIS, Appendix B, pages III-1 to III-24), (b) contingency and emergency planning (see Draft Role EIS, Appendix A, pages II-48 to II-53), and (c) any individual or cooperative research and development efforts which offer a substantial likelihood of increasing the flexibility or reliability of system operation.

BPA would also support, fund, and participate in research and development efforts sponsored by others if such effort offered a substantial likelihood of: reducing overall system energy losses, developing environmentally and economically sound resources, providing additional regional flexibility in power operations and use, or improving user efficiencies in such a manner as to reduce energy demand. BPA participation in or sponsorship of such activities would be consistent with National Energy Policy and Department of Energy efforts, and would have to be approved by Congressional budget committees.

e. Conservation

(1) Introduction

BPA proposes to make maximum use of its existing authority in pursuing energy conservation in the region. BPA conservation efforts would be designed and carried out so they complement conservation efforts of other Federal, State, and local government agencies as well as those of utilities, industries, or others. BPA would strive to coordinate regional electric energy conservation and to help achieve as much conservation as possible throughout the region and in each sector of the economy.

The BPA conservation proposal would consist of a general course of action guided by a 14-point conservation policy. The general course of action and the policy are discussed in (4) and (5) below.

(2) Authority and Responsibility

BPA would develop and carry out its conservation programs under the broad authority vested in the Administrator by the Bonneville Project Act of 1937, as amended; the Flood Control Act of 1944, the Federal Columbia River Transmission System Act of 1974, and other acts. Conservation would carry out the intent of a number of provisions of those Acts, including Section 2(b) of the Bonneville Project Act ("In order to encourage the widest possible use of all electric energy that can be generated . . . and to prevent the monopolization thereof . . ."); Section 5 of the Flood Control Act (". . . to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles . . .") and a similar passage in Section 9 of the Federal Columbia River Transmission System Act; and Section 11(b) of the Federal Columbia River Transmission System Act ("The Administrator may make expenditures . . . for any purpose necessary or appropriate to carry out the duties imposed upon the Administrator . . . including: . . . (3) electrical research, development, experimentation, tests, and investigation related to construction, operation, and maintenance of transmission systems and facilities; (4) marketing of electric power . . . .").

BPA's conservation programs would also include those programs necessary to carry out the intent and specific conservation provisions of the National Energy Act (NEA) of 1978 which apply to BPA and its customer utilities, and to extend utility conservation programs similar to those mandated by the NEA to utilities excluded from NEA coverage. Finally, BPA's conservation programs would include those necessary to carry out the intent and specific provisions of other applicable Federal legislation.

(3) Definition of Conservation

In developing and carrying out conservation policies and programs, BPA defines energy conservation to be management of the production, distribution, and use of energy to minimize consumption of scarce resources, to increase technical efficiency, and to minimize cost.

This broad definition recognizes that conservation depends on the actions of energy consumers and other decision-makers; that conservation is a means to an end (i.e., lower costs and less consumption of scarce resources); that conservation is not simply a reduction in quantity of energy consumed, but an increase in the efficiency of energy production, distribution, and end-use; and that more efficient alloction of society's resources such as energy, capital, labor and land is as necessary a condition for an action or measure to qualify as conservation as is technical (i.e., thermodynamic) efficiency. Consistent with this definition, BPA would promote cost-effective conservation of all forms of energy, focusing on the conservation of electric energy in the Pacific Northwest.

(4) General Course of Action

BPA's conservation efforts would be based on the following broad course of action and would be guided by the policy presented in the next section. BPA would seek to:

(a) Conduct the analysis necessary to determine the feasibility, cost-effectiveness, and appropriateness of specific proposed BPA conservation programs and measures.

(b) Try, on a pilot basis, energy conservation programs which appear promising, but for which more information is needed on feasibility, implementation methods, or impacts prior to BPA systemwide adoption.

(c) Develop, prepare, and implement those conservation programs which are feasible and cost-effective, within BPA's current authority, and of likely benefit throughout the region.

(d) Seek authority to conduct conservation programs which are found to be feasible and cost effective, but not within BPA's present authority.

(e) Utilize in connection with the Allocation Policy Proposal the Section 2(f) and 5(a) Bonneville Project Act authority authorizing the inclusion, in power sales contracts, of terms and conditions to effectuate the purposes of the Act (see discussion on III-25, Sales). BPA believes that provisions related to conservation will serve to further these purposes, particularly the Section 2(b) directives to encourage the widest possible use of all electric energy that can be generated and marketed and to encourage reasonable outlets therefore and prevent monopolization. A full discussion of the legal authorities on which the Administrator will rely to accomplish this general course of action, and specific conservation proposals associated therewith, are to be included in the Allocations Environmental Impact Statement.

(5) Conservation Policy

The following 14-element policy would guide program development. These 14 elements represent a mix of current national policy, current and anticipated patterns of regional energy production and consumption, and a consensus of the comments on both the Draft Role EIS and the Notice of Intent to adopt a new energy conservation policy. Further, they are all within existing statutory BPA authority and responsibility.

BPA would, as a matter of policy:

-- Treat conservation as an energy resource, viewing it as a permanent and central feature of any long-term regional energy strategy;

BPA recognizes that electric energy saved through conservation is as usable and as valuable as energy obtained from new generating facilities, and in planning for additional resources would systematically compare the feasibility and cost effectiveness of acquiring energy from conservation with the cost of acquiring energy from new generation facilities. Such comparisons would consider social and environmental costs as well as economic costs. BPA does not view conservation as a temporary measure to buy time for further expansion of energy supply from conventional generating plants, but as a permanent fixture in the regional energy picture.

-- Encourage the utilization of small-scale energy-related technology which would reduce the demand for electricity and is appropriate to local needs, skills, and available resources;

BPA would seek applications which make best use of available renewable energy sources, conserve nonrenewable resources, maximize use of local materials and labor skills, satisfy local needs, increase community energy understanding and self-reliance, and are environmentally sound. There are opportunities for these types of applications in such areas as solar energy use (heating and cooling, passive, photovoltaics, crop drying, etc.), wind energy use, use of wood, wood wastes and agricultural waste, and geothermal energy use.

-- Implement conservation programs mainly through its utility customers;

Energy consumers in the region are used to dealing with their local utilities rather than with BPA. Thus, the utilities are better able to deal directly with consumers and to monitor the effectiveness of conservation measures than BPA. In addition, the utilities have a legal obligation to meet the energy demands of the ultimate consumers they serve. Since the success of the conservation effort will be enhanced if it is a cooperative effort between BPA and the utilities, BPA would offer technical, administrative and possibly financial assistance to its utility customers to carry out conservation programs.

-- Strive to minimize adverse financial impacts on its utility customers;

Conservation might cause utilities' revenues to decrease more quickly than costs. This is particularly true for those utilities having large fixed costs such as repayment of debt incurred in construction of generation, transmission and distribution facililties. Utilities regulated by a Public Utility Commission or regulated by some other public body such as a city council may not be able to raise their rates to reflect the higher costs per unit in a timely fashion, if at all. Recognizing this, BPA would investigate ways of providing financial assistance to utilities facing these problems.

-- Strive to maintain consumers' freedom of choice, and to minimize hardship on low-income and other disadvantaged consumers in the design and implementation of conservation programs;

The efficient allocation of energy resources among competing uses, an integral part of energy conservation, should be determined by how consumers choose to spend their income. BPA programs would not infringe on the concept of consumer sovereignty--the right of consumers to buy what they are willing and able to buy at prices which reflect the costs of their decisions to society. Also, programs would consider special factors related to low income or other consumer groups.

-- Continue to seek maximum energy efficiency in BPA programs and projects;

BPA would continue to consider conservation in the planning, design, and implementation of all BPA projects and programs, and would incorporate conservation measures consistent with its established conservation goals and criteria. These internal efforts would include programs to reduce regional transmission system losses, increase the efficiency of energy use in BPA buildings, and enhance employee energy conservation awareness.

-- Encourage and support conservation through information, technical assistance, and financial incentives;

Conservation programs would include different combinations of strategies depending upon the type of end-use activity or part of the regional energy system each is designed to influence. In some cases, information and technical assistance alone would be sufficient to achieve the desired results. Programs such as conferences and workshops, distribution of printed material, radio and television public service announcements, pilot technical programs, audits of homes and businesses, infrared flyovers, and work with educational curricula can achieve substantial results. In other instances, a successful program would require financial incentives to induce consumers to undertake some conservation actions. For example, low interest loans, or low cost or "free" conservation measures may be effective in encouraging additional conservation. BPA would seek to provide these incentives, within the limits of present authority, where they are appropriate.

-- Support energy pricing which encourages conservation while avoiding artificially high prices;

BPA would not propose to adopt full marginal cost pricing in order to reduce electric power consumption. Marginal cost pricing, although theoretically sound, would impose serious dislocation and economic adjustment problems, more so in the Northwest than elsewhere in America. This is because there is a greater difference between average-cost pricing for electricity and replacement-cost pricing in the Northwest than anywhere else in America. Even with average-cost pricing, average retail prices for electricity in the Pacific Northwest are expected to increase faster than nationally because the Northwest presently benefits from a low-cost hydroelectric base. BPA would consider time-of-day rates and other measures to give the public appropriate price signals. Marginal costs would be used to determine the cost-effectiveness of specific investments or programs.

-- Encourage its customers to devote increasing financial, technical, and other resources to conservation;

BPA recognizes that many of the region's utilities have developed effective conservation programs; however, none appears to have achieved the maximum conservation that could be gained by allocating additional resources to energy conservation. Consequently, BPA would encourage more ambitious conservation programs by all electric utilities in the region, particularly those which obtain a large portion of their power from BPA.

-- Seek energy conservation in all parts of the region, all sectors of the economy, and all phases of the regional electric energy system;

BPA believes that conservation should be sought wherever it is cost effective. Electric energy saved in one sector or one part of the energy system is not inherently worth more to the region than energy saved in other sectors or parts of the energy system. For this reason, BPA would identify and evaluate programs designed to result in conservation in every phase of energy production, transmission, and consumption and in all sectors of the economy, including households, farms, commercial establishments, the energy industry itself, other industries, public agencies, and nonprofit organizations.

-- Recognize others' prior conservation efforts in designing new conservation programs;

In response to rapidly escalating energy prices and the threat of energy shortages, many consumers in all sectors of the economy have already made significant investments in conservation devices and have adopted conservation practices in their homes and businesses. BPA would take into account these efforts in the design of future conservation programs and strategies, and would strive to ensure that its conservation programs do not fail to recognize such efforts.

-- Consider achievement of energy conservation an objective in setting rates, contracting for power sales, allocating low-cost power, and other power marketing actions;

BPA would consider making conservation an integral part of these major power marketing activities. In general, it could pursue the philosophy of rewarding achievement based on the value to BPA of the energy saved.

BPA's rates and allocation efforts are interrelated, and to a large extent could be used interchangeably to encourage conservation since both ultimately provide the same incentive--lower energy costs as rewards for conserving and/or higher costs as penalties for not conserving. The extent to which allocations could be used instead of or together with rates as conservation incentives would depend on the rates established through the review and revision process, and vice versa.

-- Cooperate with other agencies and concerned parties in developing and administering conservation programs on a coordinated regional basis;

BPA would strive for a coordinated regional approach to conservation. This is the most effective way to maximize the benefits of energy conservation and renewable resources, the existing regional hydroelectric system, and the region's other power resources.

BPA would cooperate with all parties seeking to advance conservation, designing its programs to complement the authority of other Federal energy agencies or State or local governments. BPA would not compete with private industry in the implementation of energy conservation programs. BPA would, however, actively encourage and assist others with the development and implementation of programs which result in conservation. BPA would develop and implement those programs which it appeared best suited to administer or which would not otherwise result from State or local government or utility efforts.

-- Seek public participation in the development of major conservation programs;

Public participation would be sought to ensure that all viewpoints were considered and to enhance public understanding and acceptance. There are certain conservation programs which would significantly affect (or be affected by) other major BPA policies and by BPA customers and ultimate consumers. The effect of rates on conservation, for example, is only one of many questions that must be considered in addressing the spectrum of rate issues. Similarly, there are many facets to the allocation of low-cost Federal power. When conservation issues are part of the formulation of another major BPA policy, public participation would be solicited for the major policy as a whole, rather than for the conservation aspects alone.

(6) Relationship to Possible Regional Power Legislation

Both the content of regional power legislation proposed in the 95th Congress (S. 2080 and H.R. 9020; S. 3418 and H.R. 13931; and H.R. 5862) and the public comment on that legislation indicated that BPA should undertake more ambitious energy conservation efforts. The proposed Pacific Northwest Electric Power Planning and Conservation Act (S. 3418 and H.R. 13931) would have provided substantial new tools to invest in conservation. Sponsors have introduced the same legislation (S. 885 amd H.R. 3508) in the 96th Congress, but more ambitious efforts are needed immediately, with the tools available now. Thus, BPA's intent is to proceed now with conservation efforts designed to make maximum use of present authority, while also being mindful that new legislation is possible which would enable BPA to enlarge its efforts and achieve greater results.

(7) Development of Specific BPA Programs

BPA's choice of conservation programs would be the product of many considerations: applicable statutes and regulations, public involvement processes, and findings regarding feasibility and cost-effectiveness of conservation measures and the programs themselves.

Preliminary analysis of conservation measures would be conducted to determine their appropriateness from the point of view of BPA's authority, engineering feasibility, technical potential, cost-effectiveness, and overall feasibility. The engineering feasibility studies would examine the technical problems of each proposed measure. Research on the technical potential would estimate the total electric energy savings if the measure were implemented throughout the region. The next step in the evaluation process would be to assess cost-effectiveness. Cost-effectiveness is the capability to reduce energy consumption and/or production through increased efficiency at costs less than would be required to obtain the same amount of energy from alternative sources such as new generating facilities. Overall feasibility would go beyond cost-effectiveness to consider social and environmental issues and timeliness as well. This would determine whether a conservation measure or project would actually do what it was intended to do, in time and in ways that would be acceptable to the public. If necessary, pilot projects and programs would be arranged in order to develop additional information on feasibility, implementation methods, or impacts prior to BPA systemwide adoption.

After the preliminary analyses identified the attractive energy conservation technologies, specific implementation programs would be developed. These programs would be subjected to economic and environmental analysis to determine their costs and benefits and to determine their impact on the ultimate consumers of electricity, utilities, BPA, and other public bodies and economic markets. In addition to the economic/environmental analysis, major new conservation programs would be examined from other standpoints, including timeliness, reliability, compatibility with other programs and operations, customer and utility acceptability, and complexity of implementation and management.

After consideration of these and other criteria, programs which were found to be feasible and cost-effective would be proposed for implementation. A variety of measures have been suggested in regional work done to date by BPA and others, and BPA would take these ideas into account. Some of these measures and programs are the following:

- -- utility residential conservation programs (including information, inspection, installation, financing assistance, and interagency coordination);
- -- solar workshops;

- -- irrigation pump testing and other irrigation efficiency improvements;
- -- encouragement of conservation provisions in retail rates of BPA customers;
- -- information and education;
- -- reduction of regional transmission system losses;
- -- increased energy efficiency in BPA buildings;
- -- research and development of conservation measures;
- -- pilot programs on solar water heat, small wind energy conversion systems, wood heat, and residential conservation funding mechanisms;
- -- commercial building audits and other assistance and incentives to encourage businesses to conserve;
- -- programs, including incentives, to encourage industry adoption of more efficient processes;
- -- conservation-based rates;
- -- allocation of Federal power;
- -- BPA enforcement of conservation requirements through contract provisions;
- -- financial assistance to utilities from BPA;
- -- BPA "purchase" of energy saved through various conservation measures.

f. Sources of Power

Except for small amounts of firm energy which BPA may acquire in exchange for services, BPA would not acquire any new non-Federal generating resource capability on a long-term contractual basis beyond that acquired under existing exchange and net-billing agreements. However, reduced streamflows resulting from drought or other factors could reduce available Federal power below the level of BPA's power obligations. When energy purchases were necessary to meet deficits or enhance Federal system operations, BPA would purchase the output of available resources after considering their relative economic and environmental characteristics. To the maximum extent practicable, BPA would continue to offer services to integrate new regional resources into the Federal system (see "Customer Services," page III-7).

New resource planning would still be performed by individual utilities or by groups of utilities. Each utility would be responsible for determining its future energy needs and its requirement for additional resource capability from new energy projects, assisted by regional planning mechanisms. Regional power coordination would continue at no less than its current level and BPA, to the extent feasible, would encourage expanded coordination and would commit additional resources to this effort.

BPA would continue to market power from existing Federal hydroelectric and net-billed thermal plants and would encourage the Corps of Engineers and the Water and Power Resources Service to develop further feasible, cost-effective, and environmentally desirable hydro generating resources within the Pacific Northwest. BPA would also encourage storage and low-head hydro projects, and the installation of additional generators at existing hydro projects to facilitate the integration of more baseload resources if the need for and economics of such resources were identified in the planning document.

When sufficient need was identified in the regional load forecast, BPA would encourage, through expanded coordination and information efforts, the development of all cost-effective and feasible renewable, unconventional, and conventional resources proposed for development by regional power entities. This encouragement would take the form of an expanded role for BPA in the investigation of unconventional and renewable resources, with BPA actively supporting programs of States and utilities for the development of these resources. To the extent possible, consistent with environmental and other considerations, BPA would utilize the facilities of the FCRPS to coordinate and integrate any such resources with the regional power supply. BPA would expand its technical assistance to the region in the research of optimum means to integrate any unconventional resources with the region's existing generating resources and transmission system. BPA would continue its efforts in working with other agencies of the Department of Energy and with the Electric Power Research Institute to secure funds for the investigation and development of unconventional resource projects in the Pacific Northwest.

These efforts, in concert, could increase the feasibility of certain resources, thus resulting in construction of a greater number of resources. However, it is expected that the need for new resources would be determined from the regional load forecast and annual plan and so would be limited to only those needed on a regional basis. Each utility, State, or local government considering development of such resources would continue to be individually responsible for the technical investigation, construction, financing, and disposition of the output of these resources.

Nothing in this proposal would change the basic financing arrangements now required for resource construction. Investor-owned utilities would continue to finance new generation through the expansion of equity and debt at capital costs and interest rates substantially greater than those incurred by publicly and cooperatively owned utilities. Publicly owned utilities would continue to finance new facilities through the issuance of bonds whose interest would be exempt from the Federal tax on income. Each group would construct resources principally for its own needs, while using short-term power exchanges or sales to balance surpluses and deficits.

g. Sales

The Bonneville Project Act, Section 4(a), states that: "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 customers, the Administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives." 16 U.S.C. 832c(a). Similar preference provisions are contained in Reclamation Act of 1939, controlling the disposition of power from Bureau of Reclamation dams, and the Flood Control Act of 1944, controlling the disposition of power from Army Corps of Engineers dams, among others. These Acts effectively confer preference rights on public bodies and cooperatives to all Federal power sold by BPA. See the Draft Role EIS, Appendix C, pages I-2 to I-21 for a general discussion of utility law affecting regional utility operations.

As stated in the overview, BPA sent Notices of Insufficiency to its customers in June 1976. This means that current resource projections indicate that BPA will not have sufficient power to meet its preference customers' energy requirements after June 30, 1983. After that date, BPA's obligation to provide energy to its existing preference customers will be based upon a formula specified in their current power sales contracts. BPA will, of course, continue to honor all existing contracts to the date of their termination.

As existing contracts terminate, BPA will reallocate the power released by those contracts in accordance with the directives contained in existing legislation.

In order to allocate the limited amount of Federal power available, BPA has developed a proposed allocation policy which was submitted to the region for comment through the public involvement process in October 1979 (see "Public Involvement" page III-29). Subsequent to the completion of a separate environmental analysis currently underway (see 44 F.R. 57465, October 5, 1979), BPA plans to adopt an allocation policy in July of 1981 to become effective on July 1, 1983. A summary of the basic elements included in the proposed allocations policy is presented below for purposes of information only.

Summary: Under BPA's proposed policy (published in the Federal Register on October 5, 1979), BPA will serve both existing and new preference customers (PCs) regardless of the composition of their loads. Direct-service industries (DSIs) and Federal agencies (FAs) however, will no longer be served firm energy directly by BPA, and are expected to apply for service from their local utilities when their current BPA contracts expire. About half of the customers upon expiration of their BPA contracts will be considered eligible load in determining a PC's allocation. System reserve energy will also be made available to supplement remaining eligible DSI load. The policy will take effect in 1983, but a transition period is provided which guarantees that a utility will receive at least its existing contract base allocation provision until July 1, 1991, at which point the allocations will be determined from a pro-rata distribution of energy based utility net requirements. A sharing of costs and benefits provision is incorporated and a conservation reserve is established. Briefly, the main intent of the proposed policy is to minimize disruption to existing preference customers without discouraging new preference applicants. The transition period between 1983 and 1991 also helps existing preference customers to adjust to the changes which the policy will produce. The reserve capability which the DSIs provide for the region will be continued through policy provisions.

Other major elements of the proposed policy are:

-- It assures that small customers will continue to receive their full requirements through July 1, 1991, and that all other customers will receive at least their present contract base allocation.

-- BPA will offer all customers contracts with a common termination date; because in the past, staggered contract termination dates meant an inability to treat all customers uniformly.

-- Also, there are provisions for those who choose to retain their present contracts rather than sign new ones under the new allocation policy. If an existing contract is kept by a customer, the customer will receive its contractual obligations. However, upon expiration of the contract, the customer will be treated the same as any other new preference customer, which means that it will have only a minimal power supply assurance until 1991.

-- Any new load exceeding 10 average MW will not be eligible for sharing in the Federal power supply.

h. Rates

BPA's legislated rate policies would continue. Current law requires that BPA rates be set sufficiently high to recover the cost of producing and transmitting electric power, including repayment, with interest, of the Federal power investment in the Federal Columbia River Power System, over a reasonable number of years, and to recover such other costs and expenses incurred by Bonneville pursuant to law. The acts which provide legal directives for rate setting are the Bonneville Project Act (Sections 6 and 7), the Flood Control Act of 1944 (Section 5), and the Federal Columbia River Transmission System Act (Section 9). BPA wholesale rate policies and other rate matters are discussed in the Draft Role EIS, Part 2, pages VII-68 through VII-75. In addition, BPA has prepared and circulated an EIS on its 1979 wholesale rate increase. Included as part of this analysis is an examination of alternative rate structures and revenue levels and their impacts. The impacts identified in this document include those to the physical environment (air pollutant emissions, river fluctuation, irrigation development) and the effect on the need for new generation. The socioeconomic impacts identified include those to low-income households and energy-intensive industries. The alternatives considered included average cost rates, long-run incremental cost rates, time-differentiated average cost rates, share-the-savings rates, and conservation rates. BPA's revised wholesale power rates became effective December 20, 1979. The final environmental impact statement assessing the effect of the revised rates is available for public review.

The level of BPA's rates have traditionally been based on BPA's average system cost for power and transmission services, except for some deviations which provide separate charges for transformation and certain developmental and other discounts. These rates are relatively low because the major component of costs recovered are derived from relatively inexpensive hydroelectric facilities which produce energy at a lower unit cost than new resources. As a result of these low wholesale rates, retail rates of BPA's customers are also relatively low. To the extent that ultimate consumers' use of electricity is sensitive to price (price elastic), the quantity demanded is greater and more generating resources and supporting transmission facilities are required than if BPA rates were designed on some basis which would result in higher retail rates. However, both the Bonneville Project Act (Section 7) and the Federal Columbia River Transmission System Act (Section 9) require BPA to base its rates on the recovery of its costs. Both Acts also require that rates be set with a view to encouraging the widest possible diversified use of electric power. The Transmission Act specifies that this should be done at the lowest possible rates to consumers consistent with sound business principles.

Because the costs of new generating resources are much greater than the average cost of existing resources, there is a significant concern about the best method to indicate these costs through rates to consumers. BPA, as a wholesale power agency, does not directly control how its customers pass on increasing power costs to end users other than to see that retail rates are reasonable and nondiscriminatory. BPA's utility customers experience greater or lesser impact from BPA rates depending on the amount of their load they serve from their own resources, their individual distribution costs, and the allocation of these utilities' costs among categories of retail rates by the utilities and the various State regulatory agencies who approve retail electric rates.

BPA does sell power directly to certain consumers, basically large industries and Federal agencies, and so directly controls the rate they pay for electricity. The level of their rates has also traditionally been based on average system costs. Recent legislation requires that BPA consider certain Federal standards in developing rates applicable to direct-service customers. The Public Utility Regulatory Policies Act, P.L. 95-617, requires that a utility selling more than 500 million kilowatthours per year to customers other than for resale shall consider whether or not to adopt the Federal standards in the areas of (1) cost of service; (2) declining block rates; (3) time-of-day rates; (4) seasonal rates; (5) interruptible rates; and (6) load management techniques. In considering the standards a utility must make findings based upon public hearings; any determination whether or not to adopt the standards is to be in writing and available to the public. A similar process is required for a utility's consideration of Federal standards regarding (1) master metering; (2) automatic adjustment clauses; (3) information to consumers; (4) procedures for the termination of electric service; and (5) advertising. A utility is also to consider adopting a lifeline rate to supply the essential needs of residential electric customers. The Act deals with other utility rate regulatory matters as well as interutility system relationships (see "Transmission Planning and Services" above).

While BPA has already considered most of the measures to which the Federal standards pertain in setting its direct consumer rates, future BPA ratemaking will need to consider the standards set out in the Act. Such consideration will involve public hearings and will be conducted in accordance with the Act and BPA's public involvement policy (see "i. Public Involvement" immediately below).

i. Public Involvement

The Department of Energy Organization Act (DOE Act), P.L. 95-91, requires that agencies within the Department conform to the procedures set out in the Administrative Procedures Act (APA), (5 USC 551, et. seq.), as well as to certain additional procedures specified in Section 501 of the Act. On December 14, 1977, BPA published in the Federal Register (Volume 42, No. 240) a procedure providing for public participation in BPA marketing policy formulation. Revisions to Section 11 of these procedures were published in the Federal Register on Monday, September 29, 1980. These procedures parallel and in certain instances exceed the requirements placed on BPA by the DOE Act.

BPA's public participation procedures are designed to enable individuals and organizations whose interests could be significantly affected by BPA power marketing decisions to participate in the development and formulation of BPA marketing policies. Included in the procedure are: (1) public notice that a policy on a specific subject will be developed or revised; (2) an opportunity for the public to submit recommendations and suggestions on the policy; (3) notice of a proposed policy; (4) an opportunity for public comment on the policy proposal at public forums and in writing, and provision for inquiry regarding the basis of the proposal; and (5) notice of the final policy after consideration of the public comments on the proposed policy. If appropriate, BPA will develop a revised proposal and give notice of the revision. The public will have at least 30 days in which to comment on the revision. After reviewing those comments, notice of the final policy will be issued.

This BPA public participation process would be expanded consistent with BPA's expanded activities. If it would further public awareness of expanded BPA activities, BPA would utilize public opinion polls, town meetings, workshops, and "hotline" toll-free telephone numbers when appropriate to ensure public awareness of the issues involved in regional power planning and to ensure complete assessment of public attitudes prior to BPA action. BPA would also make available to the public the annual regional planning document which would serve as a background for any BPA policy development or action plan.

2. Regional Structure

a. General

Regional power system operation and development would continue within the existing institutional framework as described in the Draft Role EIS, Part 1, pages II-16 to II-55. This means that individual utilities would continue to have individual responsibility for meeting their load and load growth requirements (see the Draft Role EIS, Appendix C, pages I-9 to I-13). Although the BPA proposal assumes that regional cooperation in power operations and development would continue at no less than the present level, there is still a range of cooperative enterprise which could result. The region's utilities and States could cooperate in planning and developing the regional system, or they could work individually or on an ad hoc basis to meet the region's needs.

Congress has passed, and the President has recently signed into law, five separate acts relating to national energy policy. These acts are:

(1) The National Energy Conservation Policy Act of 1978;

(2) the Powerplant and Industrial Fuel Use Act of 1978;

(3) the Public Utility Regulatory Policies Act;

(4) the Natural Gas Policy Act of 1978; and

(5) the Energy Tax Act of 1978.

The National Energy Conservation Policy Act of 1978 provides for the development and implementation of energy conservation plans by large electrical utilities. The conservation plans must provide procedures for ensuring that effective coordination exists among various local, State, and Federal energy conservation programs.

The Public Utility Regulatory Policies Act of 1978 offers eleven voluntary standards on rate design and other utility practices for consideration by State regulatory authorities and nonregulated utilities. The Act requires that utilities and agencies consider each standard and determine if it is appropriate for conservation, efficiency and equality, and consistent with State laws. The Act also provides for the development of rules by FERC which will facilitate the use of industrial cogeneration facilities by utilities. The Act amends the Federal Power Act to grant the FERC authority to require the interconnections of electric power transmission facilities, to order utilities to provide transmission services between two noncontigous utilities, and to report anticipated power shortages. The Act sets up a loan program to aid the development of small hydroelectric projects, to investigate opportunities for energy conservation and increased efficiency in the use of facilities or resources through pooling arrangements among the utilities, and to study appropriate levels of reliability, methods of achieving levels of reliability, and methods of minimizing disruption and economic loss caused by energy outages.

In combination, the five acts establish special investigation, development, and installation programs for solar, wind, and other renewable sources of energy in Federal buildings, hospitals and public buildings, and homes financed through Federal loans or subsidies, as well as encouraging investments in such sources of energy in existing and new residences through tax credits. In sum, these acts provide procedures and structures for substantial coordination of utility operations at both State and Federal levels.

b. Utilities and Direct-Service Industries

Each utility would continue to be responsible for its own load forecasting, with a regional forecast developed from a consolidation of these, or from an independently derived, cooperatively prepared regional forecast. Each utility would also continue to be responsible for resource construction or capability acquisition to meet its load. Groups of similarly situated entities (BPA preference customers; other public bodies and cooperatives; investor-owned utilities; or industries) could join together to develop and operate resources for their own needs while selling that portion of resource output which was temporarily in excess of their needs. Contractual arrangements implementing resource construction and operation could resemble those arrangements implementing the Hydro-Thermal Power Program (see the Draft Role EIS, Part 1, pages II-13 to II-16), or could be such new forms of agreement as regional entities find appropriate. The integration of new resources into the regional power system would be facilitated through BPA provision of transmission and other services. Each utility would meet its forecasted load growth through conservation measures or construction of such types of new generating resources as appeared to be most practical given the size of its forecasted load growth and the economic and environmental compatability of a specific type of resource to serve that level of growth.

(1) Public Bodies and Cooperatives

Existing BPA preference customers, any new preference agencies, and other publicly and cooperatively owned utilities would seek new energy resources, including conservation, as power from their existing resources and any allocation of BPA power became insufficient to meet their load growth. Preference customers' need for new resources and conservation programs would be affected by BPA's allocation policy, which in turn could be affected by changes in the number of new preference customers served and the size of the load growth forecasted for new and existing preference customers.

(2) Investor-Owned Utilities

Investor-owned utilities would continue to meet load growth through conservation, renewable and unconventional resources, and the new large thermal generating resources. Investor-owned utilities would continue to finance such resources through a mix of debt and equity.

(3) Direct-Service Industrial Customers

Present BPA direct-service industrial customers have no assured long-term power supply after their existing BPA contracts expire. Under existing law, when a BPA preference customer (public body or cooperative) applies for the Federal power now contractually committed to serve the industries' loads, BPA must terminate service to industrial customers upon the expiration of their contracts and allocate that power to preference customers. Depending upon the allocation policy which BPA adopts, the direct-service industrial customers would have the following options: (1) apply for service from the utilities in whose service areas the industries are sited; (2) acquire plant capability from a plant owner; (3) construct their own resources; or (4) cease Pacific Northwest operations. Should it appear to be in the interest of the region and the Federal Columbia River Power System to retain the industries as BPA customers, BPA could seek legislative authority to continue service to them as part of its allocation policy.

c. State and Local Government

State and local siting and licensing criteria for the construction of new resources would be unaffected by either BPA or regional power entity action. State and local agencies responsible for resource siting and licensing would have access to the analysis of optimum generation and transmission sites contained in the regional planning document. This and other factors could encourage coordinated State action in the area of resource planning. State and local governments could establish mandatory conservation standards within their jurisdictions and some State regulatory bodies could require utilities to initiate conservation measures within their service areas. Coordination of such efforts could result from implementation of the National Energy Conservation Policy Act of 1978, discussed above.

d. Cooperative Arrangements

(1) Resource Operations

Cooperative agreements such as the Northwest Power Pool, the Pacific Northwest Utilities Conference Committee, the Hanford Project, the Columbia River Treaty-Columbia Storage Power

Exchange, the Pacific Northwest Coordination Agreement, and the Pacific Northwest-Pacific Southwest Intertie would continue as at present (see Draft Role EIS, Part 1, Chapter II). The region's utilities and BPA would continue to coordinate operation of their resources and systems to achieve maximum efficiency in an environmentally sound manner (see "1.b. Customer Services" above; also see the Draft Role EIS, Part 2, Chapter VII, Section B, especially pages VII-31 to VII-41).

Cooperative operation of regional resources would evolve to accommodate a greater diversity of resources as more renewable and unconventional generation was integrated into the regional system. The direction of such evolution would depend on the type and size of resources developed, and cannot be forecasted accurately at present.

(2) Resource Planning and Construction

There would be an incentive for utilities having similar characteristics, or groups of adjacent utilities, to enter into arrangements to construct generating resources compatable with the size and character of those utilities' loads in order to take advantage of economies of scale and to spread the risks of resource development among the participating utilities.

In any case, the PNUCC or a similar regional utility organization would continue to identify the need for and required characteristics of new regional resources based on the availability of other resources and on load forecasts for the region. However, individual utilities or small groups of utilities could continue to assess resource needs based upon their own analysis of future demand. The PNUCC or a regional planning organization might suggest sponsorship for the construction of resources after considering the advice and preferences of the State and Federal governments and of regional power entities and BPA regarding the compatibility of such a resource with regional needs. The specific arrangements developed among participants and plant owners for the construction of the WNP Nos. 4 and 5, Skagit, Pebble Springs, Carty Coal, Colstrip, and Pacific Northwest Generating Company plants would continue, and regional utilities would enter into similar contractual agreements to construct new generating resources in the future. However, present difficulties in developing new resources would continue, as would the disparity between the retail rates of public and investor-owned utilities.

C. Introduction to Alternatives

As mentioned on page III-1, in designing the proposal and alternatives BPA focused on the one-utility concept as its main object of evaluation. Accordingly, the sequence of Alternative 1, Alternative 2, proposal, Alternative 3, and Alternative 4, is intended to represent a range of approaches to the one-utility concept. However, the proposal and alternatives do not consist of a single action. Instead, the proposal and alternatives are each comprised of a series of actions, such as power planning, sources of power, customer services, etc.

This approach has the advantage of being able to clearly evaluate alternative approaches to the one-utility concept and of limiting the discussion to a limited and manageable number of alternatives. However, the reviewer should be aware that the actions contained under each alternative are not fixed and could be recombined in other ways.

Each BPA alternative is coupled with a description of a complementary regional structure. The coupling of a given BPA alternative to a given regional structure does not mean that one invariably follows the other. While the specific BPA alternatives and regional structures are compatible, and while certain elements in a BPA proposal may facilitate some aspects of a regional arrangement, BPA, regional utilities, States, and other entities could respond to any action by the other in a number of widely differing ways. The conjunction of a BPA and a regional alternative is meant to depict only possible or even probable actions and reactions of regional power entities.

D. Alternative 1 - Legislation Reducing BPA's Role in the Region

1. Alternative to BPA's Proposal

a. General

BPA's authority in the area of transmission construction would be significantly reduced through the repeal of those portions of the Federal Columbia River Transmission System Act of 1974 which direct BPA to integrate and transmit the electric power from additional non-Federal generating units and to provide interregional transmission facilities when these are determined to be appropriate and necessary. Thus, the Federal transmission system could not be used by BPA to facilitate any regional planning process which involved more than the delivery of Federal power to Federal customers. BPA would have no responsibility to provide additions to the Federal transmission system. It would upgrade the existing Federal transmission system and the level of its services only to deliver Federal power to preference customers and would make no efforts to assist in the integration of non-Federal resources into the regional system. BPA would make fixed allocations of available Federal power to preference customers and would deliver such power to customers as directed, but the customer would be required to provide adequate connection to the Federal transmission system to accommodate such deliveries.

One regional structure which could evolve from this lack of general access to Federal transmission would be that utilities of diverse interests would attempt to solve their transmission and resource problems independently. However, as pointed out previously, even this outcome would be dependent upon the coordinated operation of the hydro system at least to the extent it currently provides these services.

b. Customer Services

BPA's ability to provide customer services would be diminished by the fact that BPA could no longer construct additional regional transmission facilities to integrate new non-Federal resources (see "Transmission Planning and Services" below) and also would be limited by the availability of reserves from direct-service industrial loads (see "Sales" on page III-38). BPA would integrate new Federal resources and additions to existing Federal resources from within and without the region into the Federal transmission system when it was directed to market or wheel the output of such resources by Congressional, executive or secretarial direction. Should BPA have sufficient excess capacity to provide services for the shaping of non-Federal resource output or to provide forced outage reserves, such services would be offered in accordance with applicable BPA allocation policies. Those wishing to receive these services would have to interconnect with the Federal transmission system to receive them.

Once a customer had tied its non-Federal plant into the Federal system, BPA would provide the following services to the extent they were able: load factoring, forced-outage reserves, load growth reserves, and storage of energy in hydro reservoirs (see the BPA proposal "Customer Services" on page III-7 for definitions of these services). BPA would provide such services to all regional utilities to the extent that provision of these services did not reduce the amount of power which could be sold to preference customer applicants for power. However, these services would be provided on a nondiscriminatory basis under exchange agreements to all regional utilities where their provision enhanced the operating characteristics of the Federal system, or resulted in economic benefits to the system. (For examples of exchange agreements, see the Draft Role EIS, Appendix A, pages I-22 to I-31.) As preference customers required increasing levels of BPA services to integrate and firm-up additional resources, some services such as load growth reserves and load factoring would be less available to nonpreference customers. Nonpreference customers such as investor-owned utilities and direct-service industries would then acquire these services either through construction of additional peaking resources or through the interconnection and pooling of peaking resources with other utilities.

c. Transmission Planning

Because of its reduced authority, BPA would not continue its current activities and policies in planning the Federal Columbia River Transmission System (FCRTS). BPA would plan and construct the transmission system based on its own needs rather than those of the region. BPA would plan the transmission system to integrate Federal generation into its existing grid and would not consider the regional needs when planning the sytem. BPA would divest itself of lower voltage transmission lines that serve only one preference customer.

BPA would withdraw from its current leadership role in the planning portions of the regional and interregional organizations. It would continue active participation in the system operation and maintenance part of these organizations. These organizations are described under "Cooperative Activities" in the BPA proposal on page III-15.

A regional utility could finance and construct the necessary additions to the FCRTS if required to transmit non-Federal power to its loads. BPA would only monitor and review the design, construction, operation, and maintenance standards to assure that good engineering practices were followed and that the addition did not endanger the reliable delivery of Federal power. BPA would be responsible for scheduling power over jointly owned facilities to assure coordinated operation of the FCRTS.

A regional utility could build transmission parallel to the existing FCRTS to provide backup support for its own tranmission facilities.

d. Power Planning

Once BPA had allocated all its power on a single fixed allocation to preference customers as such power became available (see "Sales" on page III-38), BPA load forecasting responsibilities would be minimal, limited primarily to review of utility forecasts. When Federal power became available through the expiration of contracts or additions to the Federal generating system, BPA would utilize load forecasts prepared by each preference customer to make a pro rata distribution of such power to meet preference customer load growth to the extent possible. BPA would no longer participate in preparing load forecasts for those utilities requesting the service. Should BPA temporarily have any power available in excess of the immediate needs of preference customers, it would sell such power on a short-term withdrawable basis.

The planning assumptions which BPA currently employs in preparing its annual operating plan would remain unchanged, but would be periodically reviewed for appropriateness in the context of regional circumstances and power usage. At such time as a change in assumptions was justified based upon an analysis of power operation and of economic and environmental considerations, such a change would be made after appropriate notice to BPA customers and the public.

BPA would periodically update an information document containing a description of its operating practices, information regarding its allocation of power to preference customers, the location and characteristics of its transmission system, and such other information as was deemed appropriate. This document would serve as notice of BPA's operating plans for the short-term future.

To ensure timely and reliable delivery of Federal power to Federal customers, BPA would continue to cooperate with regional entities regarding regional reliability standards, power operating procedures, contingency and emergency planning, and such other items as would ensure reliable Federal power operations. Such standards, procedures and plans would be developed through BPA's participation in national and regional organizations with responsibilities in those areas, and through BPA's contract provisions with its customers and with regional entities who were interconnected with the Federal system.

e. Conservation

Conservation efforts would be restricted to internal programs required to carry out Federal legislation, executive orders, and administratively established programs to make Federal agencies more energy efficient as well as limited programs developed by BPA on its own to make BPA facilities in particular more energy efficient. Conservation programs resulting from the National Energy Act would be administered by the Department of Energy directly, rather than by or through BPA.

Internal programs would include reduction of energy losses on the BPA transmission system, energy "housekeeping" measures at all BPA buildings and facilities, research and development of conservation technology directly related to BPA's program responsibilities and employee awareness programs.

Information programs would be limited to responding to requests from customer utilities for information developed on conservation in transmission and communications facilities, and in BPA buildings. No public information or "outreach" programs aimed at utilities would be developed or carried out. No attempt would be made to coordinate Federal or other conservation programs in the region. No specific incentives would be developed for conservation by BPA customers or ultimate consumers. No explicit BPA conservation policy would likely be developed.

f. Sources of Power

BPA would market power from Federal hydro projects, pursuant to Congressional directives or Secretarial orders, and from the output of net-billed projects, pursuant to existing contracts. BPA would have no authority to acquire non-Federal resources beyond those currently under contract and would not attempt to replace such generation when existing plants ceased operation.

BPA would neither promote nor implement renewable resource development as it would have no responsibility to do so. Should regional utilities implement or develop such resources, BPA's system and services would be available to such utilities to the same extent it was available to other types of resource. (See "Customer Services" on page III-35.)

g. Sales

BPA could make a single fixed allocation of Federal power to meet the total load growth requirements of existing preference customers on a first-come, first-served basis. As Federal resources became available upon the termination of direct-service industrial customers' power sales contracts, those existing preference customers who could show load growth exceeding the capability of their own resources available to serve their loads over the 20-year term of the contract would receive a fixed allocation of Federal power. Any available power in excess of the immediate needs of the existing preference customers would be sold to other regional utilities under short-term contracts, with provisions making the power withdrawable to serve preference customer loads when needed.

Those direct-service industrial customers located within or adjacent to the service areas of existing preference customers could seek service from those preference customers. An allocation policy would either allow sufficient Federal power to preference customers to serve the industries' loads, or would allocate the Federal power to preference customers' loads and load growth exclusive of any large new industrial loads.

The direct-service industries, investor-owned utilities, and new preference customers who did not receive an allocation from BPA would depend upon their own resources and new energy projects to meet their energy requirements (see "Regional Structure" below). The Federal power not immediately needed to serve the load growth of existing preference customers could be purchased by these nonpreference parties to meet some of their power requirements but such sales would be subject to withdrawal at unspecified future dates.

Sales of nonfirm power would be made in accordance with the preference and prioritiy provided for by law, first priority going to public bodies and cooperatives within the Pacific Northwest region, second to nonpreference customers within the region, and then to customers outside of the region, first to preference entities and then to others.

h. Rates

The level of BPA's wholesale power rates would continue to be based on BPA's average system cost for power and transmission services. The Federal standards which the Public Utility Regulatory Policies Act sets out would be considered in accordance with that Act. The level of BPA rates would continue to be set sufficiently high to produce adequate revenues to recover costs and yet reflect the low cost of Columbia River power. BPA would continue to review its customers' retail rates for power to assure that such rates were reasonable and nondiscriminatory.

i. Public Involvement

As appropriate to BPA's reduced level of activity, BPA's public involvement program would be that minimally required by Section 501 of the DOE Organization Act and the applicable provisions of the Administrative Procedure Act. Given the level of BPA activities under this alternative and the reduced scope of its policymaking, there would most likely be few occasions for public involvement as BPA would be a "static" regional power entity, neither developing new power marketing policies nor joining with others to develop or implement new programs. BPA would continue, however, to fulfill all public participation requirements such as those of the National Environmental Policy Act and the annual budget process.

2. Alternative Regional Structure

a. General

Each utility in the Pacific Northwest would identify and plan for its own resources, or groups of similarly situated utilities would identify and plan for jointly-owned and operated resources.

Each utility would individually prepare load forecasts, rate schedules and designs, conservation plans, generation and transmission resource plans, and such other plans necessary for their own operations.

State and Federal agencies could require consistent planning and project coordination among all utilities within their jurisdictions, in regard to conservation measures, types of resources to be built, etc. Existing coordination of river operations would continue as at present.

b. Utilities and Direct-Service Industries

Public bodies and cooperatives which are currently BPA customers would receive a fixed allocation of BPA power. Once all the additional Federal power made available by the termination of the direct-service industrial customers' contracts had been allocated, the availability of relatively cheap Federal power would no longer be an incentive to the formation of new preference entities within the region. Those utilities receiving an allocation of power from BPA would plan and develop resources sufficient to meet their load growth in excess of that BPA was able to meet. All other utilities and industries would acquire resources sufficient to meet their total loads.

Each public body and cooperative would either plan and develop its own conservation and generation to meet load growth beyond the capacity of its current resources and BPA allocation, or join with similarly situated utilities to do so. These utilities might be able to rely on customer services from BPA to aid them in utilizing the output of their resources and would be able to obtain lower cost financing for the construction of resources through issuance of tax-exempt bonds.

Direct-service industrial customers would no longer receive a long-term allocation of Federal power after termination of their existing contracts, and would have to follow one of the following four courses of action:

(1) become a customer of the utility within whose service area they were situated;

(2) purchase resource capability from a large utility or a joint operating entity formed to construct new resources and seek transmission services from the Federal system, regional utilities, or a combination of these;

(3) make arrangements to construct resources within the region; or

(4) cease Pacific Northwest operations.

Investor-owned utility load growth would be met through individual or joint action in developing conservation and in constructing new generating resources. Unless there was a short-term excess of Federal system wheeling capability, investor-owned utilities would provide their own transmission from new resources to loads, upgrade a portion of the Federal system, or join with other utilities to provide common transmission lines.

c. State and Local Governments

State and local siting and licensing authority over construction of new generating resources and State regulatory authority over utilities within their jurisdiction would be unaffected by BPA or regional action. Such agencies could operate to provide some basis for the coordination of conservation and resource programs among those utilities subject to their jurisdictions, and could, through coordination of interstate standards and policies, provide for regionwide power programs and plans.

d. Cooperative Arrangements

(1) Resource Operations

There would be coordinated scheduling of the output of resources under agreements covering existing thermal resources or those planned or under construction, and such other jointly constructed and operated resources as could be tied into a centralized transmission system. BPA could provide services to assist in the scheduling of some preference entity resources, but as more such resources had to be integrated and scheduled, some BPA services could become less available to preference customers and unavailable to others.

The planning and operating reserves currently available through the interruptibility of BPA direct-service industrial customer loads would be at least partially unavailable to the region. These reserves could be available to those utilities who chose to serve these industries or to BPA preference customers through contract clauses requiring that those preference customers who serve such industries must provide for the interruptibility of the industries' loads to meet Federal customers' needs.

(2) Resource Planning and Construction

Construction of conventional thermal generating plants would be financially feasible only for the largest public or private utilities or groups of smaller utilities. Small and medium sized utilities individually would be unable to assure the economic operation of larger thermal plants due to their inability to utilize the full output of such a plant and due to the difficulty of obtaining access to a central transmission system in order to sell any excess plant capacity. Resource financing would be backed by the revenues and rate leverage of each individual utility or group of utilities. See Alternative 2 immediately below for a scenario in which regional utilities join to construct generation and transmission through mutual efforts.

E. Alternative 2 - Existing Authority, Reduced BPA Role in the Region

1. Alternative to BPA's Proposal

a. General

BPA would provide transmission and other services sufficient to deliver Federal power from Federal projects to preference customers. BPA would also offer to construct such other additions to the Federal transmission system as were needed to integrate non-Federal generation. However, regional utilities and possibly other entities, such as State, regional, subregional, and local governmental or representative agencies, would form one or more mutual operating agencies which would construct and operate generating and transmission facilities, schedule the delivery of power generated by their plants, and provide other services which participants found it economical to acquire through the agency. To the extent that the mutual operating agency (see "Regional Structure" on page III-47) provided such services, BPA's level of activity in constructing transmission system facilities and additions would diminish. Because of the central role of the Federal system in the region, most new transmission would still need to be interconnected with the Federal system for economic and environmental considerations, and BPA would upgrade the system to provide sufficient capacity to accommodate the new load.

BPA would allocate power to existing and new preference customers. New publicly and cooperatively owned utilities would be allocated power not previously committed to existing preference customers. Federal system planning would be coordinated with regional planning to the degree necessary to provide timely and reliable services to BPA customers.

This alternative is a "no action" alternative in that it assumes no new legislation reducing or expanding BPA operations nor any significant change from past BPA policies. This alternative differs from the proposal in both emphasis and degree of BPA activity. This alternative depicts a reduced level of activity on BPA's part relative to other regional activity, particularly in the area of transmission system development as a result of the activities of the mutual operating agency or agencies.

b. Customer Services

BPA's services to regional utilities would continue at current levels except that some services (e.g., load shaping or storage services) would be limited and require allocation. As in the BPA proposal (pages III-7 to III-34), BPA would provide services to all regional utilities to the extent that provision of these services did not reduce the amount of power which could be sold to a preference customer and preference applicants. To the extent that provision of services such as load factoring or storage did reduce the amount of power which could be sold from the Federal system, the service could be indirectly subject to preference and priority given by law to public bodies and cooperatives. However, these services would be provided on a nondiscriminatory basis under exchange agreements to all regional utilities where their provision enhanced the operating characteristics of the Federal system, or resulted in economic benefits to the system. (For examples of exchange agreements see Draft Role EIS, Appendix A, pages I-22 to I-31.) This means that as preference customers required more BPA services to integrate and firm-up additional resources used to meet their loads, the level of these services available to support resources of nonpreference customers would diminish.

BPA's allocation policy could provide for service to current direct-service industrial customers either directly by BPA or indirectly through BPA preference customers, or service could be terminated. If service was provided indirectly through BPA preference customers, contract provisions could require that these industries' loads be partially interruptible by BPA under certain conditions. In any case, utilities which sold power to the industries could provide for the interruptibility of that load in their sales contracts and thereby acquire the benefit of some reserves for their systems.

BPA would offer scheduling and power purchase services as requested and directed by its customers. Power would be purchased for a customer, if available, after the customer had deposited funds sufficient to purchase the desired quantity of power in a BPA trust account, and such power either could be delivered to the customer, stored for later delivery, or otherwise scheduled as the customer instructed. This and other BPA services could be provided in cooperation with or supplementary to services provided by the mutual operating agency.

c. Transmission Planning

BPA's responsibilities in planning and constructing transmission facilities would be reduced to the extent that the mutual operating agency would plan and construct regional transmission facilities. The level of cooperation between a mutual operating agency and BPA would determine the extent of continuing the "one-utility concept". The extent of representative involvement in the mutual operating agency would determine to what extent regional considerations would be included in planning future transmission requirements.

BPA would plan to construct transmission to integrate Federal hydroelectric projects and net-billed thermal plants into the FCRTS. Only if requested by a utility or the mutual operating agency, would BPA plan to construct transmission facilities to transmit non-Federal power. BPA would coordinate with the mutual operating agency to assure continued reliability of its existing system.

d. Power Planning

Consistent with the increasing role of the mutual operating agency in the region's power planning and development, BPA would assume a reduced role in coordinated regional planning activity regarding resource development and scheduling. BPA would participate in planning primarily to the extent that planned resources would affect the need for additional Federal facilities or would impact the transmission system's capacity to reliably distribute Federal power to BPA's customers.

Regional load forecasts would continue to be prepared as at present. That is, load forecasts would be developed by each utility or system in the Pacific Northwest and assembled into a forecast of the West Group Area load under the auspices of the Pacific Northwest Utilities Conference Committee (PNUCC) or its successor. (See the Draft Role EIS, Appendix A, pages II-1 to II-20.) With the formation of a mutual operating agency, that agency and similar organizations would work closely with the PNUCC and assume increasing responsibilities in preparing load forecasts and adopting planning assumptions for the service areas and loads of their participant utilities.

BPA would assist in preparing forecasts for those utility customers requesting this service. Utilities who became members of the mutual operating agency could have the mutual operating agency assist in preparing their forecasts in the future. This would facilitate the mutual operating agency's identification of resources and transmission necessary to meet the future requirements of its participant utilities using consistent planning assumptions and reflecting the particular characteristics of the mutual operating agency's available and planned resources.

The PNUCC forecasts would be used by BPA in its transmission and power marketing programs. Forecasting procedures, assumptions, and other elements, including methodology, would continue to be determined by each utility or group of utilities preparing forecasts for submission to the PNUCC.

The planning assumptions which BPA currently employs in preparing its annual operating plan would be periodically reviewed for appropriateness in the context of regional circumstances and power usage. At such time as a change in assumptions was justified based upon an analysis of power operation, and economic and environmental considerations, such a change would be made after appropriate notice to BPA customers and the public.

e. Conservation

BPA's conservation program would consist primarily of internal programs required to carry out Federal legislation, executive orders, and administratively established programs to make Federal agencies more energy efficient; limited programs would be developed by BPA to make BPA facilities in particular more energy efficient, and information programs designed to encourage conservation efforts by its utility customers. BPA would support regional conservation efforts and would participate to the extent appropriate, but it would not attempt to influence directly ultimate consumers' conservation efforts. Conservation programs resulting from the National Energy Act would be administered by the Department of Energy, some possibly in conjunction with BPA, but none exclusively through BPA.

Internal BPA programs would include reduction of energy losses on the BPA transmission system, energy "housekeeping" measures at all BPA buildings and facilities, research and development on conservation technology directly related to BPA's program responsibilities, and employee awareness programs. In addition, BPA would conduct technical research and development and studies related to general utility conservation opportunities and the effects of conservation on utilities.

BPA would not only respond to requests from customer utilities for conservation information developed during the course of other BPA programs, but would also conduct "outreach" programs designed to encourage conservation by the utilities and to support regional conservation. Such programs would include: speeches and bulletins on the need for conservation and on noteworthy examples of conservation by utilities; conservation workshops, meetings, and conferences for utilities; and other projects such as BPA's current infrared flyover program. No public information or "outreach" programs aimed at ultimate consumers would be developed or carried out. BPA would not attempt to directly coordinate Federal or other conservation programs in the region. No specific conservation incentives would be developed by BPA for its customers or the ultimate consumers.

f. Sources of Power

BPA would market power from Federal hydro projects, pursuant to Congressional directive or Secretarial order, and from the output of net-billed projects, pursuant to existing contracts. BPA would acquire no additional capability from non-Federal projects, but would market power from additions to existing Federal hydroelectric projects and from any new Federal projects built in the Pacific Northwest. This would be a continuation of BPA's existing authority and no additional authority would be sought to allow BPA to purchase or construct resource capability or to participate with regional utilities in financing or operating agreements which would make additional capability from non-Federal powerplants available to BPA.

BPA would participate in the identification, development, or application of unconventional or renewable resources through its contributions to the Electric Power Research Institute and through its participation in appropriate Department of Energy research and development efforts. It is assumed that any such Department of Energy efforts growing out of the National Energy Act would be administered in the Pacific Northwest region directly from the Department of Energy rather than through or with the participation of BPA. BPA would, of course, upgrade the Federal transmission system to accommodate the generating capacity of any unconventional or renewable resource whose owners so requested. However, a mutual operating agency could construct and operate transmission facilities to deliver power from its participant utilities' resources to the extent such facilities did not duplicate the Federal system.

Consistent with BPA's reduced regional responsibility, BPA would offer regional utilities no services in the areas of plant development and operation beyond those discussed under "Customer Services". BPA's participation in new generating resources in the region would be limited to those plants from which it has already contracted to acquire capability.

g. Sales

Federal power would be allocated to meet to the extent possible, the total load growth requirements, of existing preference customers and any new preference customers within the Pacific Northwest. New publicly and cooperatively owned utilities would be allocated BPA power that had not been previously committed to existing preference customers. The duration of allocations would be contractually specified and could vary depending on the type of load served (e.g., domestic and rural, commercial or industrial, existing or new).

New preference customers' allocations of BPA power would depend upon the pressures for creation of new preference utilities which could qualify for an allocation of BPA power, and upon preference customers' service to direct-service industrial customers upon the expiration of these industries' power sales contracts with BPA. Should an allocation be made to cover the requirements of the industrial customers who could become customers of BPA preference customers, there would be little or no Bonneville power available for new preference customers or for the load growth of existing preference customers. As an alternative to giving a long-term allocation, a policy could be established which would fix the allocation at a specific level for only a short length of time and thereafter reallocate available Federal power to new and existing preference customers on a floating or changing allocation. This allocation would continually redistribute the limited supply of power as preference customers' needs changed. The power initially provided preference customers to serve former BPA industrial customers could be subject to later preference redistribution to applicants for additional Federal power.

BPA would continue to sell surplus power and capacity in accordance with the existing preference and priority given to public bodies and cooperatives within the Pacific Northwest. That is, surplus power would be offered first to Pacific Northwest preference agencies; next, to other Pacific Northwest entities; then to preference entities outside the Pacific Northwest region; and finally to others.

h. Rates

The level of BPA's wholesale power rates would continue to be based upon BPA's average system cost for power and transmission services. The costs to be recovered through these rates would be the same as those specified under the "Rates" section of BPA's proposal. BPA rates would reflect the social objectives specified in existing legislation. BPA would also continue to ensure that the rates at which its customers resold Federal power were both reasonable and nondiscriminatory.

i. Public Involvement

BPA's existing public involvement process and procedures would continue as described under the proposal, except that a reduced level of BPA activity in transmission construction and regional planning would call for less frequent public involvement programs. Public involvement and public disclosure would be carried out in accordance with the requirements of the National Energy Policy Act, the budget process, or other Congressional or Executive directive.

2. Alternative Regional Structure

a. General

In response to forecasted regional requirements for generating resources in the Pacific Northwest, the region's utilities and possibly other regional, subregional, or local governmental agencies, including the States, could form one or more mutual operating agencies for the purposes of pooling power resources and for the development and construction of new generation and transmission facilities. Such agencies could be composed of various entities sharing common interests and characteristics, including public bodies and cooperatives, and investor-owned utilities. This would result from differences of State law and regulatory authority applied to these different groups, from geographical location of service areas, and from different interests and methods of plant financing, among other reasons.

A mutual operating agency might also supply the requirements of direct-service industrial customers, although at higher rates than they currently pay for power from BPA, and could offer them long-term power contracts. Such an agency could cooperate with industry and utility entities in the area of resource and transmission planning, and could participate with other mutual operating agencies in the construction and operation of a facility.

Because the Federal transmission system is the main regional high-voltage transmission grid, a mutual operating agency would utilize the existing Federal transmission system to the extent possible, in order to economically integrate new resources to serve loads. Where integration with the Federal transmission system was not feasible, the mutual operating agency would supplement the regional transmission system and plan for transmission additions consistent with its responsibilities to construct resources and deliver power to its participant utilities. As the regional high-voltage transmission system came under the ownership and control of a greater number of regional entities, regional utilities would have to take greater care to assure operational compatibility among regional facilities and system reliability sufficient to deliver a supply of firm power to load centers.

b. Utilities and Direct-Service Industries

Under this alternative, regional preference agencies would cooperate to form a mutual operating agency which would construct and operate new resources necessary to meet preference agency load growth requirements. Each preference agency's power costs would represent a mix of the costs of power delivered to the agency pursuant to its BPA allocation and of the new resource capability needed to meet the preference agency's loads in excess of the BPA allocation. Recently formed preference customers would participate in such a mutual operating agency as equal members, subject only to resource availability and the new utilities' financing capability.

The publicly and cooperatively owned utilities' mutual operating agency would coordinate load forecasting and other planning with existing regional entities while simultaneously performing its own load forecasting and planning functions using assumptions and methodology consistent with the interests and characteristics of its participating members.

Investor-owned utilities would either form a similar organization for their own purposes or continue to meet their load growth requirements through existing institutions in cooperation with any mutual operating agency. Being larger than many other regional utilities and having access to their own, larger resource pool, investor-owned utilities individually or collectively would be able to finance, construct, and operate large central station resources using capital raised from the issuance of debt and the expansion of equity. The investor-owned utilities would continue to interconnect resources with the Federal transmission system when feasible to transmit power from their resources to their load centers. In planning resources to meet future loads, investor-owned utilities would have to take into account the contingency that sizable segments of their service area might be served by a publicly or cooperatively owned utility in the future.

As their contracts with BPA expire, current direct-service industrial customers would seek service either from BPA preference customers, from a mutual operating agency, or from investor-owned utilities. These industries would be likely to seek power first from preference customers because of the lower cost Federal power available to them and because of the lower cost resource financing available to public bodies. A mutual operating agency might offer industries long-term contracts and use the interruptibility of industrial loads to supply its participants' system reserves.

c. State and Local Governments

State and local siting and licensing authority over the construction of new generating resorces would be unaffected by the actions of BPA or other regional entities under this alternative. Likewise, State agency regulatory authorities would remain unaffected, except that with the formation of a mutual operating agency or other State or regional utility planning organization, the State agencies could use such organizations as a focal point for their efforts in implementing conservation measures or other power marketing policies. A regionwide planning or operating agency could work with the various State regulatory agencies in developing conservation measures or power marketing policies which would be consistent for the entire region.

d. Cooperative Arrangements

(1) Resource Operations

A mutual operating agency, composed of utilities receiving allocations of power from BPA, could develop coordination agreements among its members and BPA to assure that each participant's power allocation was scheduled and delivered at the times most appropriate and beneficial to the recipient when mixed with power delivered from the jointly constructed and operated resources of the agency. The publicly and cooperatively owned utilities' mutual operating agency could also cooperate with investor-owned utilities in scheduling the use of transmission and generating facilities, would sell power surplus to its participants' needs, and would puchase and exchange such power if available and as necessary for the convenience of its participants. Mutual operating agencies and utilities would continue to cooperate with other regional entities as they do currently; however, utilities would cooperate with the mutual operating agencies in place of BPA in many areas of resource acquisition, construction, and forecasting, among others.

(2) Resource Planning and Construction

Mutual operating agencies or individual utilities would plan and construct those resources needed to meet their load growth requirements. Mutual operating agencies would develop comprehensive plans in the areas of conservation implementation, renewable resource identification and development, unconventional resource development, and any related research and development activities which would facilitate the development of feasible and cost-effective resources. The character of each utility's facility financing would remain unchanged; that is, public bodies would continue to finance new resource construction through either the issuance of tax-exempt bonds or loans from the Consumers Finance Corporation, and investor-owned utilities would continue to finance new resource construction through investors' equity and through debt procured at higher interest rates than that of public bodies.

F. Alternative 3 - New Authority, Increased BPA Role in the Region

During the 95th Congress, the Northwest Congressional delegation introduced identical bills in the Senate and House as S. 3418 and H.R. 13931. This same legislation was reintroduced in the 96th Congress as S. 885 and H.R. 13931. This alternative incorporates the basic concepts of those bills as originally introduced (not including the proposed amendments).

1. Alternative to BPA's Proposal

a. General

This alternative to the BPA proposal provides for charges in four major areas of regional power planning and operations. Briefly, these four areas are: (1) participation by the region's governors, local governments, utility and industry representatives, and the public in a statutorily defined planning process which will guide BPA's actions in regional power planning and development; (2) the sale of power to all regional utilities to meet their firm loads, to the extent that BPA has or can acquire adequate resources, and the sale of power to participating investor-owned utilities for their residential power requirements at the same rate charged preference customers; (3) BPA acquisition of resource capability, with priority given to acquiring conservation, then renewable resources, and then conventional resources, with priority given to high-efficiency conventional resources; and (4) wholesale rates which would continue to ensure full and timely repayment to the United States Treasury of all costs of the Federal Columbia River Power System, including those costs incurred in implementing this alternative, as well as the Federal investment in the existing Federal system.

b. Customer Services

BPA would offer the same customer services it currently does (see BPA's proposal), except that the amount and nature of such services provided by BPA would depend upon the kind and number of resources developed within the region. This is in turn dependent upon the cost-effectiveness and feasibility of resources and upon the load/resource forecast contained in the regional power planning and conservation program (see "Planning" below).

c. Transmission Planning

Under this alternative, BPA would be better able to implement the existing "one-utility concept" through its active involvement in the purchase and sale of power. BPA would be able to develop a transmission system that fully took into consideration the total needs and resources of the region. The major part of the responsibility for bulk power transmission would fall upon BPA. BPA would continue to consult with the region's governors, utilities, advisory councils, and public in planning and constructing future transmission facilities, but through the formal process described under "Public Involvement" on page III-56. BPA would continue to construct transmission not only for Federal hydroelectric projects and net-billed projects but for non-Federal thermal projects as well.

d. Power Planning

BPA, the State governors, and the utilities, in consultation with the advisory councils (see "Public Involvement" on page III-56) and the general public, would prepare a definitive regional power planning and conservation program. The program would cover a 20-year period and would quantify forecasted loads, conservation estimates, and available renewable and conventional generating resources by year for the region. Specifically, it would include: (1) a 20-year regional load/resource forecast; (2) proposed conservation programs; (3) consideration of rate structures which would encourage conservation; (4) proposed amounts of renewable, waste heat, cogeneration, and other resource acquisitions; (5) proposed reserves and major transmission system additions; (6) proposals for coordination of power resources with fisheries, recreation, irrigation, navigation, and flood control; and (7) any other appropriate program proposals. The program would be updated as new data became available.

In order to formulate a more accurate load forecast, a regional end-use data base would be developed. This data base, developed by BPA, the States, and utilities, would be used to formulate an annual forecast of end-use loads for the next 20 years. This forecast would be used to develop a total electric energy forecast for the region. The forecast would be used in the development of conservation programs and to identify the need for, and effectiveness of, additional conservation and resources.

e. Conservation

BPA would develop and implement all of the internal programs, information programs, and incentives discussed under "conservation" in the BPA proposal. Conservation would be treated as a resource and would be given first priority as a source of power in BPA acquisitions (see next subsection). In addition, BPA would borrow from the Treasury to invest directly in conservation measures and would seek to act as the implementing agency for all U.S. Department of Energy electric energy conservation programs in the region. If BPA were able to act as implementing agency for these programs, it could better match regional needs and opportunities with Department of Energy programs for research and development, commercialization, and technology transfer. BPA would coordinate its conservation efforts with other regional entities through development of the regional planning document.

BPA would borrow from the Treasury to finance conservation measures. This would enable BPA to develop and implement a regional residential insulation program similar to the one it proposed to Congress in 1976, and the ones currently offered by the investor-owned utilities in the States of Oregon and Washington. BPA would develop such a program to ensure that the same incentives now available only to the residential customers of some utilities would be available to all other residential consumers in the region as well. BPA would develop programs for conservation measures, in addition to residential insulation and weatherization, whenever such additional measures were feasible and cost-effective. Such programs would be completely voluntary, and BPA would work closely with suppliers and installers of conservation measures and with local financial institutions to ensure that those businesses were not adversely affected by such programs.

Electric energy conservation efforts of BPA, the States, the Department of Energy, the utilities, and ultimate consumers in the region would be coordinated; for example, BPA would, to the maximum extent possible, work through the region's utilities. As a consequence, the availability of conservation information and incentives to utilities and ultimate consumers would be relatively uniform throughout the region. Additionally, this approach would avoid any overlap or conflict with conservation programs developed by different utilities, States, or other regional entities. Realization of regional conservation potential would be significantly enhanced over current circumstances.

f. Sources of Power

BPA would acquire the necessary resources to meet its customers' loads. BPA would not build resources, except for those necessary to assure transmission system reliability when such resource construction would provide an alternative lower in cost then construction of additional transmission. In acquiring resources to meet its obligation to serve loads, BPA would give first priority to the conservation of electric power through the implementation of feasible and cost-effective measures.

In determining whether a conservation measure or other resource is cost-effective, BPA would compare the cost of the proposed resource to the lowest cost alternative resource which could feasibly serve the projected load and could be available for acquisition. This is a comparative test which would consider such factors as the power benefits, fuel availability, and prospective cost escalation of each resource.

Should it appear that feasible and cost-effective conservation would be insufficient to meet BPA's firm power obligations, BPA would plan for and acquire power from Federal and non-Federal entities to meet the remainder of its firm power obligations. Priority would be given to obtaining power from waste heat, cogeneration, and renewable resources. These acquisitions would be subject to the same test of feasibility and cost-effectiveness specified for conservation. In the event that the regional plan indicated that these acquisitions would be insufficient to meet BPA's obligations, BPA would make additional plans for acquisitions from other resources, including conventional powerplants, giving priority to feasible and cost-effective high efficiency resources.

In implementing conservation programs and in acquiring resources, BPA would follow the regional plan. The type, quantity, sponsorship, and other necessary characteristics of acquired resources would be based upon the regional program, the results of consultation with the governors and the advisory councils, the public comments received, national energy policies, and environmental and economic considerations. Proposals for the acquisition of resource output would be submitted for regional and Congressional review (see "Public Involvement" on page III-56).

In addition, BPA would work with regional power authorities, utilities, and the Department of Energy to investigate and develop programs for resources which were compatible with regional needs but which had not yet been proven feasible, cost-effective, or of sufficient capability or reliability to meet loads. These regional efforts would be carried out under the auspices of regional entities, BPA, the programs established under the National Energy Act, or a combination of these.

g. Sales

BPA would offer to sell electric power to all Pacific Northwest utilities to meet that part of their regional firm load in excess of their resources committed to firm load, provided that BPA had or could acquire adequate resources. The enhanced resource planning and development process which would result under this alternative should enable BPA to acquire sufficient resources, in the form of conservation or power from generating facilities, to meet regional load growth.

Public bodies and cooperatives would retain their statutory preference to Federal power. While BPA would be authorized to execute contracts with nonpreference customers, the provisions of the Bonneville Project Act would continue to require the termination of power sales contracts with investor-owned utilities when necessary to enable BPA to serve a competing application from a public body or cooperative. The statutory preference of public bodies and cooperatives to power under contract to direct-service industrial customers, once such contracts expired, would continue unimpared.

BPA would offer investor-owned utilities an amount of electric power for resale sufficient to meet their residential loads. This power would be sold at the same price as that sold to preference customers. The benefits of investor-owned utilities' reduced wholesale power cost would be passed through to the residential customers. Sales to investor-owned utilities would be conditioned upon BPA's acquisition of an equal amount of power either from the investor-owned utility at the average system cost of its resources or from other resources at an equal or lesser cost. Such sales would be phased-in over a 5-year period in which BPA would offer to meet up to 50 percent of the utilities' residential loads in the first year, and increase the percentage in equal annual increments to 100 percent at the end of 5 years.

BPA would offer to sell power to direct-service industrial customers if these sales would provide a portion of the region's planning and operating reserves. These reserves would be provided through BPA's ability to restrict or interrupt service to the direct-service industrial customers to help assure reliable service to other customers. BPA would offer new long-term power sales contracts to the industries implementing the terms of this alternative at rates substantially higher than they currently pay (see "Rates" below). Other industries wishing to become direct-service industrial customers could do so if there was power available to serve them and if their service would also provide regional reserves.

To the extent that additional power was available, BPA would offer it for sale to any utility or customer. This power would be from relatively expensive new resources and could be withdrawn, upon 5-years notice, if it were needed to serve a preference customer's load. If it were needed, the preference customer would receive it at average resource cost (see "Rates" below).

Surplus sales would be treated as they are currently and would be limited by availability, preference laws, and P.L. 88-552, which gives first call to this power to Pacific Northwest users.

h. Rates

As in the proposal and Alternatives 1 and 2, rates would be established which (1) were sufficient to assure repayment of Federal investment in the Federal Columbia River Power System after meeting BPA's other costs; (2) were based upon BPA's total cost of service, including contingencies and funding required for conservation measures; and (3) insofar as transmission rates were concerned, equitably allocate the cost of the Federal transmission system between Federal and non-Federal users. In addition, rates would be set to recover BPA's costs incurred in carrying out the provisions of this alternative; e.g., conservation investment, acquisition of resource capability, and other authorized programs. All rates would become effective upon confirmation and approval by the FERC. Rates would be reviewed and revised as often as every year and at least once every 5 years.

(1) Preference Customers and IOU Residential Loads

BPA would set wholesale rates for the sale of power for the general requirements of public bodies, cooperatives, and Federal agencies, as well as for the power sold to the investor-owned utilities for their residential loads. These rates would recover the cost of that portion of the Federal hydroelectric and net-billed thermal resources used to meet these loads. When additional resources were needed to meet these customers' requirements, their rates would also recover the additional costs of the electric power necessary to serve the loads, first from the electric power purchased under agreements with investor-owned utilities in exchange for power to serve their residential customers' requirements, and next from the power from new resources.

(2) Direct-Service Industrial Customer Rates

Until July 1, 1985, Bonneville would set a rate applicable to direct-service industrial customers which would recover the net costs incurred by Bonneville in exchanging power with the investor-owned utilities for their residential and small farm customers in addition to the costs Bonneville incurs in serving the DSI load and any adjustments for the benefits of the planning and operating reserves the DSIs provide. After July 1, 1985, the rates applicable to direct-service industrial customers would be set at a level which Bonneville determined: (1) was equitable in relation to the average electric rates charged major industrial customers by the region's public utilities taking into account the comparative size and character of the loads served, the relative cost of electric capacity, energy, transmission, and related delivery facilities, and the cost of other service provisions related to the delivery of power to such customers; and (2) took into account the costs incurred in serving these customers and the benefits of the planning and operating reserves they provided. Additionally, prior to the first submission to the Department of Energy of rates developed under the terms of this alternative, direct-service industrial customers' rates could include a surcharge on their existing rates at that time. These surcharged rates would be the then existing industrial power rates plus an amount by which exchange power costs exceeded Federal hydroelectric and net-billed thermal resource costs, and an amount to cover the costs of Bonneville's initial conservation efforts.

(3) Other Rates

BPA's current authority to establish a uniform rate or rates for the sale of capacity would continue. All other firm power rates would be based on the cost of the proportions of the Federal hydroelectric resources, the net-billed thermal resources, and any additional resources which BPA determined were required to support such sales. Furthermore, BPA would have authority to allocate among power rates all of the costs and benefits of conservation, uncontrollable events, reserves, operating services, sale of excess electric power, and any other costs and benefits which BPA determined to be appropriate for a rate to incur.

i. Public Involvement

BPA would actively solicit and consider the comments and opinions of Pacific Northwest States, local governments, utilities, ratepayers, and the public at large in the development of major electric power policies. This would be done through consultation with the governors, formation of a permanent BPA Consumers Council and a permanent Bonneville Utilities Council, and through the development of comprehensive programs designed to inform the public of major issues and to obtain their views. The intent would be to provide ample opportunities for these parties to participate in the development of proposals related to major power issues in the region while these issues were in the formative stage.

In consultation with Pacific Northwest governors, BPA would also work closely with the State departments of energy in the preparation of load forecasts, resource and conservation planning, resource acquisitions, major transmission system additions, and other significant program proposals. BPA staff would participate with the individual States in data gathering and in the preparation of planning studies and reports.

BPA would submit the regional power planning and conservation program, major revisions of such program, and proposals for acquisition of major power resources to the Governors of Idaho, Montana, Oregon, and Washington, and to the BPA Consumers Council and the BPA Utilities Council for final review and comment. Should two or more of the governors of States having 35 percent or more of the region's population, or two-thirds of the members of either the BPA Consumers Council or the BPA Utilities Council notify BPA of their disapproval of the program, revision, or power resource acquisition within 30 days after its proposal, BPA would notify Congress of such disapproval. It would then submit other data or information provided by the governors, the BPA Consumers Council, or the BPA Utilities Council, along with its own comments, to Congress for review. Any member of Congress could request a vote of the body as a whole for a resolution disapproving the proposed program, program revision, or proposed acquisition of a major power resource.

Before BPA contracted for the acquisition of a major resource (one with a capability of 50 MW or more, or the equivalent), it would submit the proposal for final review to the governors and the councils. After their review, BPA would submit their views, together with the proposed agreements and evidence of compliance with the National Environmental Policy Act of 1969, to the Senate Energy and Natural Resources Committee and the House Interior Committee for review. BPA would also publish notice of the proposed acquisition in the Federal Register.

BPA would periodically advise the councils of construction plans and operation of resources acquired to meet BPA power obligations. The councils could investigate the planning, construction, and operation of the resource and submit their findings and recommendations to BPA. BPA would be required to report to the councils regarding its disposition of their recommendations.

2. Alternative Regional Structure

a. General

Under this alternative, regional utilities, State energy authorities, and other power entities would continue their traditional roles in power planning and development. BPA would have the ability to assist in the coordination of resource planning and development to the extent that it would be responsible to supply power to meet utilities' and industries' loads. However, utilities would have the option to continue to plan and build resources and distribute power to meet their loads. State regulatory authorities would continue to set retail rates for utilities under their jurisdiction; and State siting authorities would continue to have authority over construction and siting of resources. Coordinated resource development could occur as a result of the regional power planning and conservation program, developed through regional participation, and as a result of the purchases of resource capability by BPA.

b. Utilities and Direct-Service Industries

Public bodies and cooperatives would retain their statutory preference to Federal power; investor-owned utilities could acquire power from BPA over a 5-year period to serve the requirements of their residential customers at the preference power rate upon exchanging an equal amount of power with BPA at their average system cost. Direct-service industrial customers could acquire power under new long-term contracts, but at higher rates. Additional power would be sold to regional investor-owned utilities at a rate based upon the cost of new resources. Any of these entities could also construct resources for their own power needs, apply the generation from their existing resources to meet these needs, acquire power from sources other than BPA, and generally carry on their own power programs.

Existing or new BPA preference customers would acquire power from BPA for that portion of their load, exclusive of major new industrial loads, which they did not meet from their own resources. Resources constructed by public agencies to serve their own requirements are eligible for financing through bonds whose interest is exempt from the Federal tax on income. These bonds are sold at lower interest rates than other bonds of comparable quality, and this results in substantially lower plant costs. Because of a 1972 IRS regulation implementing a 1976 amendment to the Revenue and Expenditure Control Act, BPA is no longer considered an "exempt person" so that if it acquired more than 25 percent of the output of a generating facility financed by a public agency the interest on the bonds used to finance the plant would not be tax exempt. Existing law would be changed to grant BPA "exempt person" status when purchasing the capability of a plant for the requirements of preference customers. Thus, should preference customers need to meet their requirements from generating resources, BPA could purchase the needed capability without the preference customers losing their source of low-cost construction financing.

Investor-owned utilities currently finance only a portion of the construction of new resources through debt. This alternative would allow full debt financing of resources for which 75 percent or more of the capability was acquired by BPA. As in the case of preference customers, this would allow investor-owned utilities to jointly utilize the output of resources.

Current BPA direct-service industrial customers would be offered long-term contracts at new rates. These contracts would provide that a portion of their service would be interruptible to provide the region with operating and planning reserves. Should the industries find that alternative sources of power were more attractive they could refuse the long-term contracts and purchase from alternative sources when their existing contracts expired. However, if the alternative source of industrial power were a regional utility acquiring power from BPA, that utility would be required to pay for a portion of their BPA allocation equal to the amount of power it sold to the industrial customer at a rate based upon the cost of new resources.

c. State and Local Government

State and local government siting and regulatory authority over utilities would remain unchanged. To the extent that such entities participated in the regional power planning and conservation program, the development of consistent interstate policies and plans would be facilitated. The planning and conservation program would also provide State authorities early involvement in the utility planning process and easier access to facts and opinions regarding the regional power situation. State authorities would, however, continue to have the final word on matters within their jurisdiction.

d. Cooperative Arrangements

(1) Resource Operations

BPA would acquire output from or integrate most regional resources. There would be maximum coordination of resources based upon economic scheduling and other constraints. This would allow waste heat, cogeneration, and renewable resources to assume a more reliable role in serving regional power needs. BPA and other utilities would integrate these resources into the regional system and provide backup or storage facilities to make these resources firm and more feasible.

(2) Resource Planning and Construction

Through the exchanges provided by the meetings of the councils, and the comment from the governors and the public, a single comprehensive regional power plan would be developed based on regional resources, conservation programs, loads, and environmental considerations (see "Planning" above). Regional resources would be planned to meet forecasted loads. Conservation would be the priority resource, and renewable resources would be emphasized and made more feasible. Conventional resources would be constructed when higher priority resources could not meet the load requirement and/or the higher priority resources were not cost-effective or feasible. BPA would aid in financing new resources through the acquisition of resource capability.

G. Alternative 4 - New Authority, Regional Energy Commission

In March 1977, Representative James Weaver of Oregon introduced H.R. 5862. The bill was revised in November 1977. This alternative incorporates some of the basic principles of that bill.

1. Alternative to BPA's Proposal

a. General

A Regional Energy Commission with authority to determine regional energy policy would be established and, in cooperation with BPA and regional non-Federal utilities, would provide integration, pooling, and marketing of all the electric energy in the region. Conservation and a preferential rate for all domestic and rural customers would be achieved under the direction of the Commission. Under its direction, BPA would become the energy wholesaler for the Pacific Northwest, purchasing all electric energy generated or acquired by participating utilities and assuming a full public utility responsibility to serve those utilities' loads. As part of this arrangement BPA would undertake the construction or acquisition of such additional resources as needed to meet loads which cannot be met from existing conservation or resources

For the purposes of this alternative, the authorities and duties of the Commission and BPA will be treated together. The Commission would function as a board of directors to BPA, setting policy and directing BPA's actions.

The Governors of Washington, Oregon, Idaho, and Montana would each appoint one member of the Commission and the President would appoint one member and designate the chairman. The Commission would determine regional energy policy for the generation and purchase, integration and pooling, and marketing of electric energy in the region. The Commission would prepare and publish forecasts of Pacific Northwest electric energy conservation, demand, load, and resources. It would be held responsible for keeping the supply of electric energy in balance with the demand.

b. Customer Services

BPA would offer full requirements contracts to all participants in the Pacific Northwest. A participant would be any regional utility which sells all its electric energy, either that which it acquired or generated, to BPA. Under full requirements contracts, BPA would assume a public utility responsibility to serve its customers, a duty it does not now have and would not have under the other alternatives. Public utility responsibility is generally characterized as comprising (1) the duty to serve all users of the type and in the territory the utility has proposed to serve; (2) the duty to render adequate service; (3) the duty to serve at reasonable rates; and (4) the duty to serve without discrimination. For a discussion of public utility responsibility, see Draft Role EIS, Appendix C, pages I-9 to I-13. BPA would either construct or acquire the necessary facilities to meet these responsibilities.

BPA would offer nonparticipants load factoring services, forced outage reserves, load growth reserves, and storage in Federal hydro reservoirs if sufficient resources were available and if such services would not affect system integrity or reliability. Under provisions of the Pacific Northwest Coordination Agreement, BPA would continue to provide storage, when such capacity was available, for any of the other cosigners of the agreement.

c. Transmission Planning

The Regional Energy Commission would have the authority to direct and authorize BPA to continue its current activities in planning, designing, and constructing the Federal Columbia River Transmission System. The Commission would adhere to the "one-utility concept" of taking the total regional needs and resources into consideration when developing alternative transmission facilities. BPA would have a duty to plan and construct all high-voltage transmission for participants. Current transmission policies, avoiding duplication of facilities, providing consistent reliable transmission services, development of high-voltage transmission facilities, using existing right-of-way, planning the system based on long-range requirements and projections, reducing losses to conserve energy, and development of multi-use corridors, would continue. BPA would have a duty to plan and construct all transmission facilities to transmit Federal hydroelectric generation and all thermal plant generation including non-Federal resources for participants.

d. Power Planning

BPA would prepare and publish forecasts of Pacific Northwest electric energy requirements, peak demand, conservation, and resources. Regional utilities would participate in the forecasting by providing information and data upon demand. BPA would independently acquire data and prepare forecasts and studies which were necessary or appropriate to enable BPA to carry out its utility responsibility for participants' loads.

The forecast would cover a 20-year period and would quantify forecasted loads, conservation goals, and renewable and conventional generating resources by year, utility, and State for the region. Specifically, it would include: (1) a 20-year regional load/resource forecast; (2) proposed conservation programs; (3) model rate structures which would encourage conservation; (4) proposed amounts of renewable, waste heat, cogeneration, and other resource acquisitions; (5) proposed reserves and major transmission system additions; (6) proposals for coordination of power resources with fisheries, recreation, irrigation, navigation, and flood control; and (7) any other appropriate program proposals. The program would be updated each year as new data became available.

In order to formulate an accurate load forecast, a regional end-use data base would be developed. This data base, developed by the Commission with assistance from BPA, the States, participants, and nonparticipants, would be used to formulate an annual forecast of end-use services for the next 20 years. This forecast would be used to develop a total energy forecast which would include the electric energy forecast. This forecast would be used in the development of conservation programs and in the identification of the need for additional generating resources.

e. Conservation

In order to carry out Commission policies for balancing energy demands and supplies, BPA would develop and implement all of the internal conservation programs and many of the conservation information programs and incentives discussed in the proposal. The Commission's assumption of a public utility responsibility would be accompanied by authority to use stronger, more direct conservation incentives.

The Commission would have the authority to promulgate regionwide conservation standards, establishing required thermal efficiency for new and existing buildings, energy efficiency for household appliances and industrial processes, etc. BPA would be responsible for developing such standards, in cooperation with the Department of Energy, the States, and interested groups. In addition, BPA would use wholesale rates, power sales contracts and other incentives to encourage State and local government adoption of such standards and to penalize noncompliance by energy consumers.

BPA would also use direct retail rate review more aggressively to ensure that retail rates encouraged conservation and penalized energy waste by consumers. BPA would formally review utility and industrial customers' conservation programs to ensure that such programs were effective and consistent with other conservation efforts in the region.

While BPA would have the responsibility and authority to acquire sufficient energy supplies to balance energy demands and thus would not have to allocate fixed supplies, it could use energy allocations as conservation incentives in a number of ways. One would be to withhold some or all low-cost Federal power from wholesale or retail consumers who were determined to be significantly less energy efficient than other comparable consumers. Another way would be to make a separate allocation of low-cost Federal power available for development and operation of industries that were particularly energy efficient or contributed to the energy efficiency of other consumers (e.g., insulation or solar equipment manufacturers).

BPA would borrow funds from the U.S. Treasury to invest directly in conservation measures, as discussed in Alternative 3. Such investment would not be limited to residential weatherization or similar conservation measures, but would include a variety of measures beyond the present limits of Federal power marketing agency authority and responsibility. Such investments might include increases in energy efficiency of existing industries, support of location and development of energy-efficient new industries, and financial participation in industries which contribute to energy efficiency of other energy consumers (e.g., insulation or solar equipment manufacturing). In addition, BPA would reimburse utilities and State or local governments for the costs they incurred in implementing conservation requirements imposed by the Commission.

As a Federal agency, BPA could act as the implementing agency for all Department of Energy conservation programs in the region, and could match regional needs with Department of Energy programs. In addition, BPA would be helping to implement many of the State programs for which the Commission was responsible.

f. Sources of Power

BPA would be responsible for keeping the supply of electric energy in balance with demand. Reducing the demand for energy would be given as much consideration as increasing the supply of energy. In achieving a balance between the supply of and the demand for electric energy, BPA would give full consideration to both of the following alternatives: (1) reducing the need for new generation through a variety of conservation programs designed to result in the adoption of conservation measures by all types of energy consumers; i.e., residential, commercial, and industrial consumers; and (2) electric energy resources through the use of solar, wind, geothermal, fossil fuels, organic fuels, tidal, cogeneration, hydro, or nuclear technologies.

The Commission would set the policy for the acquisition, sale, and disposition of electric energy purchased and generated by BPA. BPA would purchase all existing and new electric energy generated or acquired by participants in order to assure an adequate supply of power for the participants. Nonparticipants could construct generating resources if they chose to. In the event that some chose not to participate and constructed their own resources, BPA would offer to coordinate and integrate nonparticipant resources into the system to the extent that it had the capability without compromising the integrity or reliability of the system.

g. Sales

The Commission would set the policy for the sale of electric energy by BPA. BPA would offer to meet every participant's full requirements. Preference would be given to publicly and cooperatively owned utilities. When available, nonfirm and surplus power would be offered to participants. Participants would have to resell this power within their service area. To the extent power was available and if the sale would not compromise the integrity or reliability of the system, BPA would offer nonfirm and surplus power for sale to nonparticipants and to utilities outside the region.

h. Rates

BPA would sell the available energy in the BPA pool to participants within the Pacific Northwest under the following two price categories:

(1) Rate I energy the lowest production cost for use by the general public, domestic and rural, for energy requirements of units of city, county, and State government, and for the operation of publicly owned transportation systems; and

(2) Rate II energy all the electric energy in the BPA pool in excess of that in the Rate I pool for use in meeting the remaining energy consumer demand not met by Rate I energy.

Schedules of rates and charges of electric energy in the BPA pool would be prepared and made effective by the Commission. The rate schedules would be modified from time-to-time and would be fixed and established with a view to encouraging the wisest use and conservation of electric energy.

In establishing rate schedules for sale of electric energy, preferential (lower) rates would be given to domestic and rural consumers in order to provide each domestic and rural consumer a minimal amount of energy having the lowest cost of production. Each of the States, counties, cities, and publicly owned transportation systems in the Pacific Northwest would be given the same preferential rate as given to domestic and rural consumers for their requirements of electric energy to provide governmental service.

After review and approval of rates by the Commission, BPA would sell to each distributing utility its share of Rate I energy based upon the kWh needed to supply the eligible demand for Rate I energy for each such utility. This energy would be sold to eligible Rate I energy consumers of the distributing utility with only the costs of distribution, generation, and transmission, as approved by the respective electric energy regulatory agency in each State, added to the BPA wholesale rate.

The remaining energy available in the BPA pool (Rate II energy) would be sold at a price that includes all the costs (generation and acquisition) of energy production and transmission not included in establishing the price for Rate I energy. Rate II energy would be used to meet the remaining energy requirements of consumers of electric energy in the Pacific Northwest who are not eligible for Rate I energy.

Under existing law, the schedules of rates and charges for transmission, the sale of electric power, or both such schedules, would provide for uniform rates throughout prescribed transmission areas. The recovery of the cost of the Federal transmission system would be equitably allocated between Federal and non-Federal power using such a system. Rate schedules would be drawn having full regard for the recovery of the costs of producing, pooling, and transmitting such electric energy, including amortization of capital and conservation investment over a reasonable period of years.

i. Public Involvement

In addition to fulfilling the requirements of BPA's current public participation procedure, the Commission would hold public hearings prior to making a determination regarding: the construction of generating facilities by BPA or the Corps of Engineers; the approval of generating facilities to be constructed by a participant and purchased for the BPA pool; conservation activities; guidelines and policy for the use of water in the Columbia River Basin; emergency curtailment of electric energy; and other such policy determinations.

In order to communicate the concerns of the general public to the Commission and to assist it in its deliberations, a Local Government Advisory Committee would be formed. The Local Government Advisory Committee members would consist of at least 20 elected local government officials plus a number from each State reflecting the relative population of the various States. Members would be appointed by the governors of the respective States.

2. Alternative Regional Structure

a. General

In the planning and construction of generating resources and major transmission facilities, the one-utility concept would become a reality. Participating utilities would assume primarily distribution functions. Direct-service industries would continue to receive power and provide system reserves. The States would control resource siting and set consumer rates as at present. The Commission would determine regional energy policy and, in cooperation with BPA and non-Federal utilities, provide for the generation and purchase, integration and pooling, and marketing of all the electric energy in the region.

b. Utilities and Direct-Service Industries

All participating publicly owned, cooperatively owned, and investor-owned utilities would receive their full load requirements from BPA. Their primary responsibilities would lie in energy distribution, customer services, and billing. Participants would develop energy resources for their own use only where they could do so more economically than BPA or where a utility or group of utilities owned a resource that had not been authorized by the Commission and whose output had not been acquired by BPA. All participants would assist the Commission in load forecasting.

Nonparticipating utilities would operate essentially as they do now, being responsible for their own load forecasting, planning, system construction, and distribution. BPA would cooperate, to the extent feasible, with nonparticipants and, to the extent that the nonparticipants request it, would integrate and coordinate resources, wheel power, store energy, and provide other such services.

Direct-service industrial customers would be assured a power supply, and they would continue to provide system reserves. Current and new direct-service industrial customers would have equal access to the BPA pool.

c. State and Local Government

States would determine resource siting and set rates. The Commission would guide resource siting from a regional standpoint; however, the States would hold the ultimate siting approval. Retail rates would be reviewed by BPA to assure that the benefits of the FCRPS were being passed through to the retail consumer, but the States would regulate retail rates.

The Commission and BPA would consult with the Governors of Idaho, Montana, Oregon, and Washington regarding regional power planning, construction, acquisition, and sales. The governors would appoint the advisory council members of their respective States. This council would be composed of local elected officials and assist the Commission in its duties.

d. Cooperative Arrangements

(1) Resource Operations

Utilities, both participants and nonparticipants, would operate and maintain their own resources. Resource operations would be fully coordinated by BPA for the bulk of the region's resources, as they would be purchased by BPA. BPA, in cooperation with the participants, would direct operations and set schedules based on the most efficient and environmentally sound means. Thermal and renewable resources of participants would be coordinated with the hydro resources. The balance of the region's resources, those of the nonparticipants, would be integrated into the system to the extent that system integrity and reliability would not be compromised.

(2) Resource Planning and Construction

Resource planning would be on a regional basis to meet the total regional load, not individual utility loads. The regional forecast produced by BPA would be a composite of the individual loads which would be determined by specific end use data provided by the participants. The end use data would be standardized by assumptions and methodology to assure consistency.

BPA would either construct needed resources or acquire the output of resources built by the Corps, the Bureau of Reclamation, or participants. Participants could retain the use of the their own new generation if its output was less costly than Rate II energy.

CHAPTER IV

ENVIRONMENTAL CONSEQUENCES

CHAPTER IV - ENVIRONMENTAL CONSEQUENCES
INTRODUCTION

This chapter assesses the environmental impacts of the regional power supply system, both as it has evolved to the present and in terms of alternative institutional frameworks for future development, described in Chapter III. In addition to the institutional assessment is an analysis of the environmental impacts of potential future power resources. The specific adverse impacts associated with future power resource development are not known, because resource mixes, i.e., relative proportions of new generation to be contributed by each resource type, and their locations are not known. Accordingly, a worst-case analysis was utilized. It is very unlikely that any of the five worst-case scenarios described in this chapter would actually develop. Some combination of the resources described in the scenarios will be the most likely outcome.

Because the scenarios present worst-case impacts of potential resource developments, it is assumed that they encompass the range of potential impacts of resources under any of the alternatives, including the proposal. The purpose of this worst-case analysis is to demonstrate the maximum possible environmental impact from the development of a given resource type or technology. The actual impacts that would occur as a result of the proposal and alternatives would most likely be less than those of the scenarios.

In addition to the worst-case scenarios, a summary representation of the NRDC Alternative Scenario has been included in this Final EIS. The Alternative Scenario, although similar to Scenario B, is distinguished from the other scenarios in that it is portrayed as an exercise in the possible. In doing so the Alternative Scenario also supposes particular policies by regional entities rather than relying on the technical potential of resources. It is included here because it was submitted as part of NRDC's response to the Revised DEIS and because it deals with the need to bring about institutional changes to accomplish its resource objectives. The importance and effect of institutional mechanisms is the focus of the FEIS. A detailed technical evaluation of the Alternative Scenario prepared by BPA is presented in Attachment C to this Final EIS.

In conducting the evaluations reflected in the EIS, the regional power supply system was examined as a whole. As a result, the discussion in this chapter includes the impacts of the Federal Columbia River Power System as well as non-Federal hydro and thermal facilities built to serve regional electrical firm loads, whether or not those facilities are located within the geographical BPA service area.

This chapter is divided into five parts. Section A describes the impacts associated with the development and operation of the existing/committed regional system, including current marketing practices. This section is intended to serve as a baseline of system impacts for purposes of comparison of additional impacts of subsequent developments. In addition, Section A provides a discussion of BPA's customer service policies.

Section B includes a discussion of several recurring themes identified in the process of evaluating the proposal and alternatives. These major themes include: (1) the influence of alternative levels of cooperation and coordination; (2) the potential for load-resource imbalances; and (3) the effect upon nonpower considerations. Section B also includes a discussion of the generic impacts of 21 resource technologies. The potentials for these technologies are then combined in this section to present renewable and conventional future energy resource scenarios.

Section C focuses on BPA's ability to affect the selection of specific types of power resources for the region, and compares BPA's influence to other factors which can also affect resource selection.

Section D discusses the impacts or influence of the proposal and alternatives upon probable resource directions. Included in this discussion is an examination of the affect of BPA's provision of services upon resource development.

Finally, Section E summarizes the information in Sections B and D. This section is designed to facilitate a comparison of the total environmental impacts that would be incurred under each of the alternatives and the proposal. A discussion of the requirements of non-NEPA environmental laws and how BPA's proposal and alternatives meet those requirements is also included in this section. The comparison concludes with a discussion of the environmentally preferable alternatives.

A. Impacts of the Existing and Developing System.

1. Energy Resources.

a. Generation.

Although unaffected by the proposal and alternatives, a description of three key planning assumptions is included as an attachment to this draft. These three assumptions deal with (1) reliability; (2) critical period planning; and (3) influence of the existing grid. These three areas were of some interest during the review of the original Role DEIS and are provided as background information.

At the present time, the Pacific Northwest power supply system has a total system peaking capability of 33,700 MW. With those hydro and thermal units presently under construction or committed, peaking capability will increase to 49,030 MW by 1990.

Figure IV-1 shows the location of major hydro and thermal generating facilities in the region. Facilities are shown for reference purposes only.

(1) Hydro System.

(a) Description of the Hydro System.

1. Description and Status of Projects.

a. FCRPS.

Table IV-1 lists Federal Columbia River Power System resources and their general specifications. Total peaking capability at 30 Federal projects was about 20,100 MW as of April 1, 1980. Additional units under construction will add about 3,300 MW of capability. Additional authorized units, if constructed, would increase the total FCRPS peaking capability by approximately 2,700 MW.

While a significant amount of peaking capacity will be added to the FCRPS by completion of units under construction, no new storage will have been added, therefore, these installations will do little toward meeting the baseload needs of the region over the next few years.

b. Mid Columbia River Public Agency Projects.

Five mid-Columbia projects are owned by public utility agencies. These are the Rock Island and Rocky Reach projects, owned by Chelan County PUD; the Priest Rapids and Wanapum projects, owned by Grant County PUD; and the Wells project, owned by Douglas County PUD. Additional units are under construction at Rock Island. Mid-Columbia project characteristics are summarized on Table IV-2.

TABLE IV-I

FEDERAL COLUMBIA RIVER POWER SYSTEM

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

December 31, 1979

Project	Type	Utility, State	Stream	Initial Date in Service	Existing		Under Construction		Authorized—Licensed		Potential		Project Totals		SCHEDULED ON-LINE
					No. of Units	Peaking Capability—kW	No. of Units	Peaking Capability—kW	No. of Units	Peaking Capability—kW	No. of Units	Peaking Capability—kW	No. of Units	Peaking Capability kW	
Albeni Falls	H	C. of Eng. Idaho	Pend Oreille	Mar. 25, 1955	3	49,000	—	—	—	—	—	—	3	49,000	
Anderson Ranch	H	WPRS[1] Idaho	S. Fk. Boise	Dec. 15, 1950	2	34,500	—	—	—	—	1	17,250	3	51,750	
Big Cliff	H	C. of Eng. Oregon	N. Santiam	Jun. 12, 1954	1	20,700	—	—	—	—	—	—	1	20,700	
Black Canyon	H	WPRS Idaho	Payette	Dec. 1925	2	10,200	—	—	—	—	—	—	2	10,200	
Boise River Div.	H	WPRS Idaho	Boise	May 1912	3	2,250	—	—	—	—	—	—	3	2,250	
Bonneville	H	C. of Eng. Ore.-Wash.	Columbia	Jun. 6, 1938	10	574,000	8-2	576,000	—	—	—	—	18-2	1,150,000	May 81-Jul 82
Chandler	H	WPRS Washington	Yakima	Feb. 13, 1956	2	13,000	—	—	—	—	—	—	2	13,000	
Chief Joseph	H	C. of Eng. Washington	Columbia	Aug. 20, 1955	27	2,412,120	—	—	—	—	13	1,808,950	40	4,221,070	
Cougar	H	C. of Eng. Oregon	S. Fk. McKenzie	Feb. 4, 1964	2	28,750	—	—	1	40,250	—	—	3	69,000	Sept 86
Detroit	H	C. of Eng. Oregon	N. Santiam	Jul. 1, 1953	2	115,000	—	—	—	—	—	—	2	115,000	
Dexter	H	C. of Eng. Oregon	M. Fk. Willamette	May 19, 1955	1	17,250	—	—	—	—	—	—	1	17,250	
Dworshak	H	C. of Eng. Idaho	N. Fk. Clearwater	Sep. 18, 1974	3	460,000	—	—	3	759,000	—	—	6	1,219,000	
Foster	H	C. of Eng. Oregon	South Santiam	Aug. 22, 1968	2	23,000	—	—	—	—	—	—	2	23,000	
Grand Coulee	H	WPRS Washington	Columbia	Sep. 28, 1941	23-2	5,852,400[3]	1	805,000	—	—	6	4,830,000	30-2	11,487,400	1981
Grand Coulee PG	PG	WPRS Washington	Columbia	Dec. 30, 1974	2	100,000[2]	4	200,000	—	—	—	—	6	300,000	Dec 80-Dec 81
Green Peter	H	C. of Eng. Oregon	Middle Santiam	Jun. 9, 1967	2	92,000	—	—	—	—	—	—	2	92,000	
Hills Creek	H	C. of Eng. Oregon	M. Fk. Willamette	May 2, 1962	2	34,500	—	—	—	—	—	—	2	34,500	
Hungry Horse	H	WPRS Montana	S. Fk. Flathead	Oct. 29, 1952	4	328,000	—	—	—	—	—	—	4	328,000	
Ice Harbor	H	C. of Eng. Washington	Snake	Dec. 18, 1961	6	693,300	—	—	—	—	—	—	6	693,300	
John Day	H	C. of Eng. Ore.-Wash.	Columbia	Jul. 17, 1968	16	2,484,000	—	—	4	621,000	—	—	20	3,105,000	
Libby	H	C. of Eng. Montana	Kootenai	Aug. 29, 1975	4	483,000	4	483,000	—	—	—	—	8	966,000	Nov 85
Libby Reregulating	H	C. of Eng. Montana	Kootenai		—	—	3	87,700	—	—	—	—	3	87,700	Nov 85-May 86
Little Goose	H	C. of Eng. Washington	Snake	May 19, 1970	6	931,500	—	—	—	—	—	—	6	931,500	
Lookout Point	H	C. of Eng. Oregon	M. Fk. Willamette	Dec. 16, 1954	3	138,000	—	—	—	—	—	—	3	138,000	
Lost Creek	H	C. of Eng. Oregon	Rogue	Dec. 1, 1977	2	56,350	—	—	—	—	—	—	2	56,350	
Lower Granite	H	C. of Eng. Washington	Snake	Apr. 15, 1975	6	931,500	—	—	—	—	—	—	6	931,500	
Lower Monumental	H	C. of Eng. Washington	Snake	May 28, 1969	6	931,500	—	—	—	—	—	—	6	931,500	
McNary	H	C. of Eng. Ore.-Wash.	Columbia	Nov. 6, 1953	14	1,127,000	—	—	10	1,207,500	—	—	24	2,334,500	
Minidoka	H	WPRS Idaho	Snake	May 7, 1909	7	16,000	—	—	—	—	—	—	7	16,000	
Palisades	H	WPRS Idaho	Snake	Feb. 25, 1957	4	135,000	—	—	—	—	2	155,250	6	290,250	
Roza	H	WPRS Washington	Yakima	Aug. 31, 1958	1	12,900	—	—	—	—	—	—	1	12,900	
Strube	H	C. of Eng. Oregon	S. Fk. McKenzie	—	—	—	—	—	1	5,175	—	—	1	5,175	Sept 86
Teton	H	WPRS Idaho	Teton	—	—	—	—	—	3	30,000[4]	—	—	3	30,000	
The Dalles	H	C. of Eng. Ore.-Wash.	Columbia	May 13, 1957	22-2	2,015,000[5]	—	—	—	—	—	—	22-2	2,015,000	
Total Number of Units and Peaking Capability					**190-4**	**20,121,720**	**20-2**	**2,151,700**	**22**	**2,662,925**	**22**	**6,811,450**	**254-6**	**31,747,795**	
Total Number of Projects					**—**	**30**		**1**		**2**		**0**		**33**	

[1] Bur. Rec. is now Water and Power Resources Service.

[2] Grand Coulee PG is not included in the total number of projects.

[3] Includes two Grand Coulee station service units at 11,300 kW each that are available for load, 18 units of 126,100 kW each, three Third Powerplant units of 650,000 kW and two units at 805,000 kW.

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

[5] Includes two fishway units at The Dalles of 15,100 kW each, 14 units of 89,700 kW each, and 8 units of 98,900 kW each. Due to high tailwater, the plant capability is reduced 28,300 kW with 21 units and 62,200 kW with 22 units generating.

BPA—Branch of Power Resources April 1980

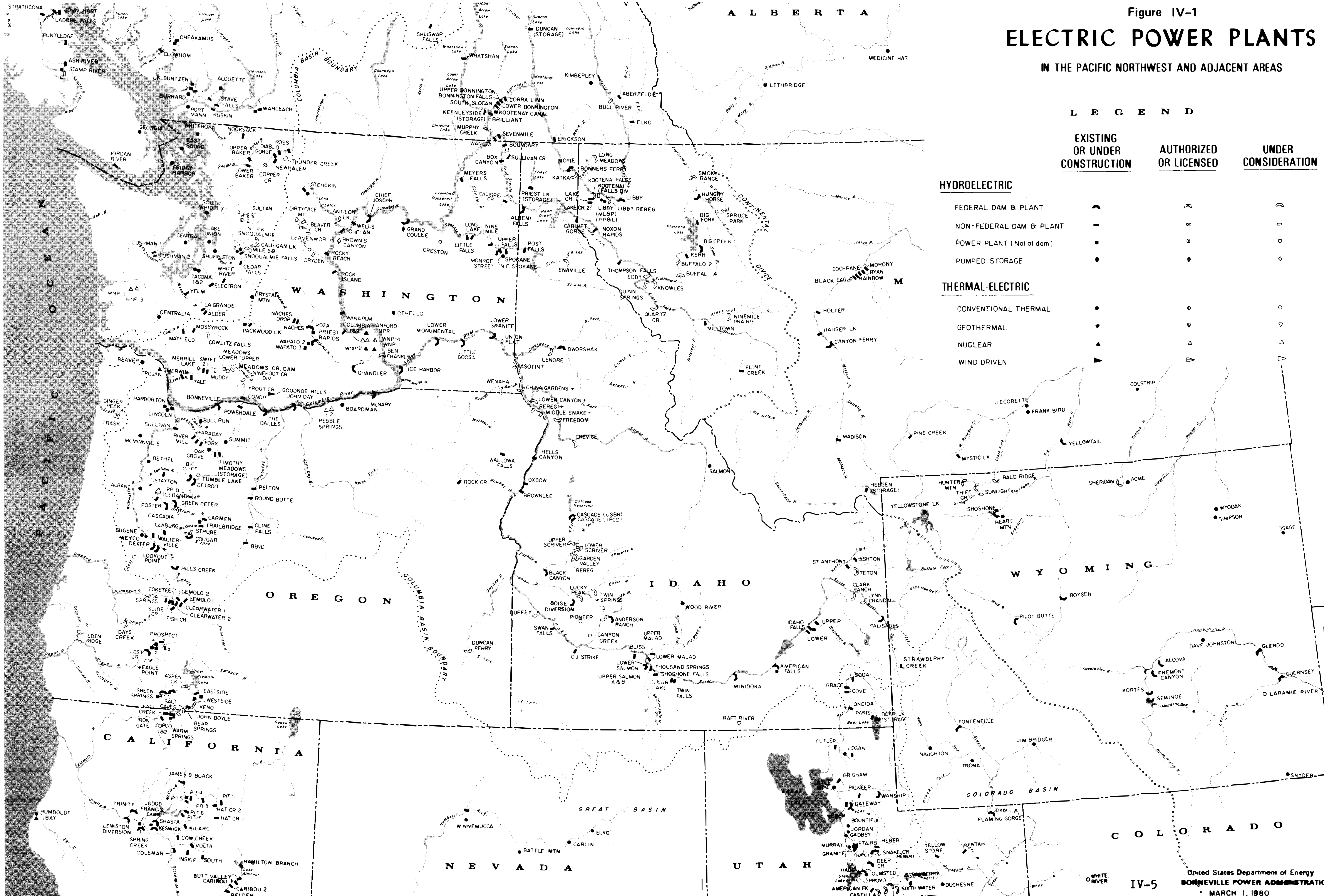


Figure IV-1
ELECTRIC POWER PLANTS
IN THE PACIFIC NORTHWEST AND ADJACENT AREAS

TABLE IV-2

MID-COLUMBIA RIVER PUBLIC AGENCY PROJECTS
PROJECTS EXISTING AND UNDER CONSTRUCTION

Project	Ownership	Location	Initial Date of Service	Existing No. Units	Existing Total Capability, MW
Rock Island	Chelan Co. PUD	Washington	1933	18	622
Rocky Reach	Chelan Co. PUD	Washington	1961	11	1,213
Wells	Douglas Co. PUD	Washington	1967	10	774
Wanapum	Grant Co. PUD	Washington	1963	10	831
Priest Rapids	Grant Co. PUD	Washington	1959	10	788
TOTALS				59	4,288

2. Operation of the Hydro System.

a. Basics of River Regulation.

Impacts of operating hydropower resources must be evaluated with respect to both daily and seasonal characteristics. Within each time frame, both energy production and capacity (peaking) production must be considered to describe the full spectrum of operational effects associated with changes to the configuration of the hydropower system. To aid understanding of future changes in operations of major regional hydropower resources, it is first necessary to explain a few fundamental concepts: types of power, types of projects, and the annual storage regulation cycle. (Role DEIS: A,II-21 to II-48 and III-1 to III-45)

(1) Types of Power.

(a) Energy

The energy generation of a hydroelectric plant is directly related to the head, or vertical distance the water falls, at the project and the volume of water which passes through it. For example, 100 million acre-feet of water passing through the turbines at McNary Dam will produce 6.5 million MWh of electric energy. Briefly, energy production is a simple function of availability of water and a conversion factor.

(b) Capacity.

Over the course of a day, electrical use in the Pacific Northwest varies from a relatively low rate in the early morning hours to a high rate in the later morning and early evening hours. The level of power consumption at any instant is commonly referred to as demand.

The generation available to meet the instantaneous demand variation at a hydroplant is termed capacity. Varying the capacity over the course of a day to maintain a precise balance between generation and demand constitutes the peaking operation. Capacity is a function of a large number of parameters, including physical plant characteristics, generator outages, allocation of reserves, magnitude of prevailing streamflow, and instantaneous elevations of forebay and tailwater surfaces.

(2) Types of Projects.

For power production purposes, hydroelectric projects are classified according to both the storage capacity of their reservoirs and the functions those reservoirs perform. Many projects commonly referred to as "reservoir" projects actually are "pondage" projects which have little usable storage. The dams at Bonneville, The Dalles, and McNary, and the four Federal projects on the Lower Snake River are examples of pondage projects. These large projects generate considerable amounts of electric energy but the amount of usable storage is small relative to riverflows. Also, their forebays generally operate in ranges of 5 feet of elevation or less. To regulate streamflows to meet power demands, reservoir surface elevations at pondage projects often rise and fall each day.

A true storage reservoir project, by virtue of its capability to release and store water as needed to meet changing system peaking requirements, provides more flexibility of operation than a pondage project. "Annual" storage reservoirs, such as Franklin D. Roosevelt Lake behind Grand Coulee Dam, usually refill each year even if drafted to minimum levels, i.e., if all "live storage" is withdrawn. "Cyclic" storage reservoirs, which may have less capacity than annual storage reservoirs, may not refill each year if drawn down to minimum levels. The Hungry Horse, Dworshak, and Libby project reservoirs are cyclic and normally are not drafted to minimum levels for power production.

Both pondage and storage reservoir projects of the FCRPS perform "pondage operations." That is, reservoir surface elevations at both are varied on hourly, daily, and weekly bases to regulate streamflows for power production. Thus, short-term reservoir operations at storage projects generally are similar to operations at pondage projects.

Longer-term, or seasonal, reservoir operations at storage projects differ substantially from reservoir operations at pondage projects. While the reservoirs of pondage projects are limited to operate within a relatively small range of elevation throughout the year, reservoir surface elevations at storage projects may be drafted hundreds of feet, according to seasonal drawdown and refill procedures. Pondage operations superimpose short-term reservoir level variations of a few feet per week on seasonal drawdown and refill operations of much greater magnitude.

Later discussions within this subsection describe the changes in reservoir operations expected to occur at FCRPS projects due to the addition of generating units currently under construction.

(3) Annual Regulation Cycle.

There are three principal storage operation seasons for Columbia River reservoirs east of the Cascade Mountains: the summer holding or storage conservation season, fall and winter storage control or drawdown season, and spring snowmelt runoff or refill season. West of the Cascade Mountains the hydrology differs, so winter is the flood season, due primarily to rainstorms.

Consequently, there are four operation seasons for reservoirs in the western part of the basin and coastal drainage areas: the summer holding season, fall drawdown season, winter flood season, and spring refill season. Weather variations influence the exact timing and magnitude of reservoir regulation seasons each year.

The reservoir system east of the Cascades usually fills by July or early August. Reservoirs west of the Cascades usually are full or nearly so by early May. After a reservoir fills it usually is held as full as possible during the summer to enhance recreation and conserve water for later use. However, some reservoir storage drawdown (draft) occurs in the summer when necessary for irrigation, water supply, power generation, and low flow augmentation to improve water quality and aid navigation. Reservoir storage is reduced further by increased summer evaporation and recharge of groundwater pools. The amount and timing of seasonal drawdown varies at individual reservoir projects depending on weather, load conditions, and the purposes for which the project was constructed.

Reservoir system draft accelerates in the fall, usually in late September or October when natural riverflows recede, temperatures begin to drop, daylight periods are shorter, and power demands increase. At the same time, recreational use of lakes and reservoirs decreases. There also is a need under most conditions to draft storage space at many projects for winter flood control by November or early December.

Most of the reservoirs west of the Cascades fill gradually in February. As the flood potential from winter rains diminishes, the amount of reservoir space maintained for flood control gradually decreases.

The high flow period on the Columbia River and its tributaries east of the Cascades usually occurs during the spring due to snowmelt runoff. Accumulated snowpacks are measured monthly after the first of January to forecast the total seasonal runoff and peak river stages. Most reservoirs east of the Cascades are drawn down in preparation for controlling the forecast floods, and usually are at their lowest elevations in March or April. Snowmelt runoff begins to increase significantly by mid-April and usually peaks in June. During the melt period hydrometeorological data are used daily for operational forecasting. A portion of the resulting high flows is stored to reduce flood stages and refill reservoirs.

b. Hydro Peaking Transition.

The Pacific Northwest is undergoing a transition from using hydroelectric energy as its baseload to a thermal base with hydro providing the peaking. This will lead to increased river fluctuations in the 1980's. In addition to the description that follows the reviewer is referred to Appendix A of BPA's original DEIS for a more detailed discussion of hydro and hydropeaking operations and their impact. A number of refereces to specific portions of Appendix A are provided in the following discussion.

(1) Seasonal Storage Operations.

Seasonal drawdown and refill operations at major FCRPS storage reservoirs at Grand Coulee, Hungry Horse major FCRPS utilization of the new generating units associated with the transition of the hydro system from meeting baseload needs to peaking. Basically, each of the four major storage projects will continue to follow the same general patterns of past years into the mid-1980's, and no departures from current flood control or seasonal power production practices are anticipated. Minor differences in the timing, rate, and depth of drawdown will occur each year due to variations in streamflows and short-term generation requirements. Figure IV-2 shows the general guidelines for seasonal operation of Grand Coulee and the three major cyclic storage reservoirs of the FCRPS.

Special operations at major storage projects may continue to influence the timing and magnitude of reservoir drawdown and refill cycles during some years. These operations, such as special drafts to provide sufficient flow for fish migration or advance energy to industries during critical-water years, significantly alter seasonal operations (Role DEIS: A, II-42-48 and III-45).

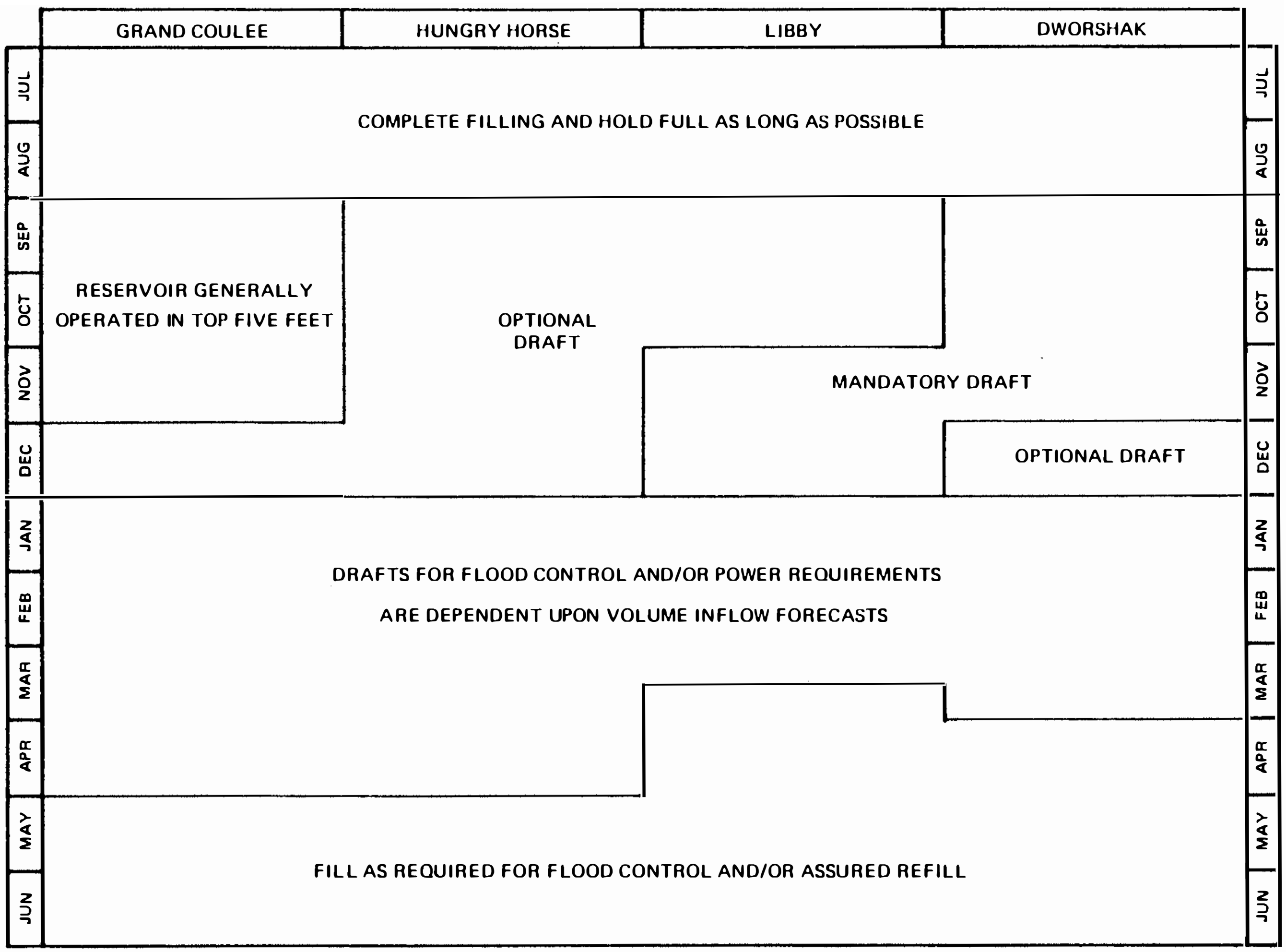
Due to Canadian construction and implementation of the Kootenay River Diversion, operation of the Libby reservoir is expected to change significantly beginning with the 1984-85 operating year. The Diversion, to be located in the Canal Flats area, will divert up to 1.5 million acre-feet of water from the Kootenay River into Columbia Lake each year. Canada will construct and operate the Diversion within limits set forth in the Columbia River Treaty.

Water diverted from the Kootenay River will reduce inflow to Libby reservoir, necessitating revised operations to help assure refill. While drawdown and refill operations at Libby probably will continue to occur at about the same rate each year, the total depth of draft necessarily will be less than it would be under similar streamflow and load conditions prior to 1984-85 because of the net reduction in water available below the diversion.

Studies to determine the precise effect of the Kootenay River Diversion on the Libby project have been performed and results have been shown in the PNUCC's West Group Forecast studies since 1977.

Figure IV–2

SEASONAL STORAGE RESERVOIR OPERATING GUILDLINES



Source: Columbia River Water Management Group, 1976

(2) Pondage Operations.

The direct effects of adding more units for peaking will occur at the modified projects (see Table IV-1) during daily and weekly pondage operation cycles. Generally, addition of generating units will improve the hydro system's ability to provide the varied levels of generation required for load following. Consequently, discharge rates and water surface elevations at modified projects will fluctuate more frequently and by greater magnitudes than in the past.

The specific hydraulic effects of peaking modifications will vary among projects due to differences in their locations, capacities, and operational characteristics. Effects of peaking modifications at individual projects also will depend on prevailing streamflows, plant loading and reserve requirements, and several other factors that influence, or shape, short-term pondage operations.

(a) Hydraulic Balance.

The maximum flow of water that can be passed through the turbine of a generating unit is referred to as the "hydraulic capacity" of that unit. Similarly, the maximum or "full gate" flow that can be passed through a powerplant with all generating units operating is termed the hydraulic capacity of that plant. For several years the hydraulic capacities of powerplants on the Columbia and Snake Rivers have been "out of balance" with one another because the capacities of some projects are more fully developed than others on the same river. The addition of generating units currently under construction at these plants will significantly improve the hydraulic balance among them (Role DEIS: A, III-8).

The general effect of an improved hydraulic balance between two plants is to reduce fluctuations of the downstream project reservoir level and to reduce the need to spill water. When two adjacent projects discharge water at equal rates, the volume of water between the projects does not change. Thus, two adjacent plants with identical hydraulic capacities can be operated at maximum capability, or "peaked," simultaneously without causing a change in the volume of the reservoir between them.

(b) Changes in Daily and Hourly Generation Patterns.

Hydro generation patterns will be dictated by the following factors. First, hydro plant additions will allow greater variations in generation at an individual plant while helping to reduce the system peaking requirements (Role DEIS: A, III-1, 2). Second, modifications of power sales contracts will lessen the amount of off-peak energy that can be returned to the Federal system. This will help to maintain minimum flow requirements in the river by increasing the night-time loads. Peak pricing techniques may also be instituted to help reduce the differences in daily generation between peak and off-peak hours (Role DEIS: A, IV-77). Third, new thermal plants will tend to increase the necessary load-following response of the hydro system since thermal plants run more efficiently as "baseload" continuously operating units (Role DEIS: A, II-75).

(c) Tailwater Fluctuations and Reservoir Fill/Drawdown Patterns.

Generally speaking, future hourly tailwater fluctuations will increase with the completion of the presently authorized hydro system, but the greater hydraulic capacity will allow more flexibility of operation. Computer simulation studies have shown that while tailwater fluctuations will increase in the future, reservoir elevations behind each dam will tend to fluctuate less due to the improved hydraulic balance between projects (Role DEIS: A, III 6).

3. Coordination.

a. Influence of Coordination Arrangements.

Coordination agreements among utilities within the Pacific Northwest have profound effects on the operations of all hydropower plants in the region. First, the Pacific Northwest Coordination Agreement establishes a methodology for planning the seasonal operations of storage plants, which ensures that firm loads will be met while also providing for reservoir refill. Second, the Coordination Agreement employs a number of devices designed to capitalize on diversities that exist among utilities' hydropower systems. Mutual storage provisions, for example, capitalize on streamflow diversity, so that utilities with excess water can store that water in the deficient utilities' reservoirs upon payment of a nominal service charge. A third effect is created by a provision which permits the interchange (or exchange) of capacity and energy between utilities on a seasonal basis to ensure that no individual utility will be forced to operate its reservoirs in an inefficient manner. Another provision allows one hydro plant owner to deliver energy to another in lieu of releasing water from upstream storage projects. This is an especially important provision since it prevents operations that would diminish the quantity of water held in storage reservoirs while hydro plants elsewhere in the region were spilling (wasting) energy.

Finally, the Coordination Agreement establishes a contractual form of reserve pooling that takes advantage of forced outage diversity among participating utilities. As a result, individual utilities are required to carry less reserve than they would if operating in isolation, and consequently, are able to sell more firm power.

The basic tool for implementation of the Coordination Agreement is an annual operating plan. The plan is similar to resource planning studies in that it combines the operating characteristics of thermal and hydroelectric plants with load estimates and historical streamflow data. There is one important difference, however. Resource planning studies determine the resources that would be needed to meet a projected load, while the annual operating plan determines the size and shape of load that can be met with available resources. The plan is the fundamental guide to month-by-month operation.

A second coordination arrangement, the Mid-Columbia Hourly Coordination Agreement, deals with instantaneous plant loadings during daily operations. Although the Hourly Coordination Agreement does not deal with all Northwest resources as the Pacific Northwest Coordination Agreement does, it efficiently coordinates a complex subgroup of closely coupled hydro resources in the region: the mixed ownership projects on the Columbia River from Grand Coulee through Priest Rapids.

The goal of hourly coordination is to obtain increased energy while simplifying power system (especially hydro subsystem) operating procedures and enhancing nonpower river uses. In operational terms, hourly coordination enables Mid-Columbia River plants to meet a given load with higher average reservoir levels and smaller pond fluctuations than would occur with independent operations. The savings from such an operation end up in the form of stored water in an upstream reservoir (usually Grand Coulee) which, when released at a later time, will make additional power generation possible at each Mid-Columbia plant.

Operation of a set of resources under single ownership will produce more load-carrying capability than operation under diverse ownership. Through voluntary adherence to Northwest Power Pool (NWPP) principles, contractual operation under the Pacific Northwest Coordination Agreement and the Mid-Columbia Hourly Coordination Agreement, and the eventual formulation of a thermal coordination agreement, utilities in the Pacific Northwest will approach the efficiency of a single ownership system.

b. Influence of Other Contractual Arrangements.

A large number of other contractual arrangements, in addition to the coordination agreements, have significant influences on hydropower operations. BPA has entered into a variety of exchange agreements (with a very broad range of terms) with each utility to which it is interconnected, including utilities in California (Role DEIS: A, I-26-31, II-32; C, II-33-34). Each of these agreements enables the delivery of energy excess to the needs of one party, and provides emergency and breakdown relief power on a voluntary basis.

Terms of these agreements may affect hourly peaking operations and seasonal storage supplies. The resulting effect of the agreements with Northwest utilities is a substantial increase in daytime, weekday generation levels for the FCRPS. The primary effect of exchanges with California utilities involves increased daytime peaking at Lower Snake and Lower Columbia pondage plants. Regardless of region, these agreements tend to make fullest use of available resources. They make efficient, economic use of installed peaking capacity at pondage plants while alleviating draft and assuring refill at seasonal storage projects.

(b) Impacts of the Hydro System.

1. Biotic Resources.

a. Fisheries.

The Columbia River and its tributaries provide the Northwest with a unique fishery resource consisting of both resident fish and anadromous species such as Pacific salmon, steelhead trout, sturgeon, shad, and smelt. Of these, steelhead and salmon are the most important economically, providing sport and commercial fisheries valued in excess of $130 million annually (NMFS, 1979). 1/ Besides their economic value, these fish are a part of the history of the Northwest, especially of the native American tribes whose utilization of Columbia River salmon and steelhead was an important facet of their culture (Role DEIS: A, III.A.).

Resident fish have not received the research and management attention afforded the migratory species, although they are also affected by hydro operations (Corps, 1980). 2/ The diverse fresh water fishery provides recreational opportunity for sport fishermen rather than a large economic resource supporting a commercial fishery (Role DEIS: A, III.A.).

The development of the Columbia River for irrigation flood control, navigation, and hydroelectric generation, beginning in the early 1900's, has been a major cause of recent declines in Columbia River salmon and steelhead populations. Initially, dams prevented fish from reaching their natal habitat--Grand Coulee blocked over 1,100 miles of habitat. Later, as the system continued to be developed, increased installation of turbines, flow manipulation, and a series of slack water reservoirs have imposed significant mortality on both adult and juvenile migrant fish (Chaney, et al, 1976) 3/.

Although the construction and operation of dams on the Columbia River and its tributaries have been a major cause of declining salmon and steelhead runs, there have been other important factors. Irrigation diversions, poor logging, farming, and grazing practices, dredge mining, and other factors have eliminated and degraded habitat throughout the Columbia Basin (WA DOE, 1980). 4/

The heavy demands placed on salmon and steelhead by both off-shore and in-river commercial exploitation, as well as by the sport fisheries, have also contributed to decreasing numbers of adult fish returning to their natal waters (ODF&W, 1979). 5/ A combination of all the above factors has brought populations to levels where the National Marine Fisheries Service and U.S. Fish and Wildlife Service have initiated a review of upriver stocks of salmon and steelhead for possible listing under the Endangered Species Act. (Federal Register, Vol. 43, No. 192, p. 45628).

Efforts to protect salmon and steelhead have been characterized as ". . . good to fair, too little-too late, to none. . . . " The Mitchell Act of 1939 established Federal tax revenues to restore and enhance salmon and steelhead runs of the Columbia Basin (Chaney, et al, 1976). 3/ Since 1949, over $84 million has been provided for a variety of activities including construction of fish ladders, removal of logjams, and construction and operation of fish hatcheries.

In the late 1950's, the then seven Northwest State and Federal fisheries agencies formed the Columbia Basin Fisheries Technical Committee to coordinate efforts to protect the fisheries resources of the Columbia Basin. This group is now a sub-committee of the Columbia River Fisheries Council and has effectively coordinated fisheries concerns with the river operating agencies through the Fisheries Research and Protection Program Technical Coordination Committee and the Committee on Fisheries Operation (Columbia River Water Managment. Group, 1977 and 1978). 6/ 7/

Other efforts to coordinate activities aimed at understanding and protecting the valuable fishery resource of the Columbia River and its tributaries are being carried out by the Pacific Northwest River Basin Commission and the Columbia River Fisheries Council. BPA is assisting this effort by providing funds for research and development projects which fall within the guidelines of BPA's Fishery Program and are related to hydroelectric operations.

Mortalities associated with juvenile salmon and steelhead emigration to the Pacific Ocean have been of major concern to the Fishery management agencies. The initial cause for concern was the immediate loss of mainstem and tributary spawning and rearing habitat resulting from the construction of multipurpose dams (Chaney, 1978). 8/ Mitigation for these projects in the form of fish hatcheries, ladders, and other devices, associated with improved hatchery techniques, habitat improvement, and other management efforts resulted in a general improvement in fish populations through the early 1960's (WA DOE, 1980). 4/ However, since the mid-1960's a series of events have resulted in serious mortalities to all upriver populations of salmon and steelhead.

The first of these events is related to high nitrogen levels at and between mainstem dams, which have approached 135 percent to 140 percent of saturation. Nitrogen supersaturation is blamed for mortalities ranging from 40 to 95 percent of all Snake River juvenile salmon and steelhead migrating downstream during 1965-75 high flow years (Chaney, et al, 1976). 3/ Since the mid-1970's, this problem has become less acute with the completion of large headwater storage reservoirs and installation of additional turbines in mainstem dams. This combination has eliminated uncontrolled spill in all but extremely high runoff years. The construction of "flip lips" at key Corps and Public Utility District dams and priority spill requests have further reduced the nitrogen supersaturation problem. A significant amount of information on nitrogen supersaturation has been developed since the early 1970's. References for this discussion may be found at the end of Appendix III, BPA Role EIS (BPA, 1976). 9/

During low flow conditions and, with the hydraulic balancing of the mainstem hydroelectric projects (BPA, 1976), 9/ during most average water years, the majority of Columbia River water now runs through the turbines. A number of studies have estimated that juvenile salmon and steelhead passing through turbines suffer direct mortality of from 7 percent (Bell, et. al., 1972) 10/ to 30 percent (Long, et. al., 1968, 1975) 11/ 12/ when indirect mortality associated with predation of stunned or injured fish is considered (Corps, 1980). 2/ During the low-flow water years of 1973 and 1977, the National Marine Fisheries Service estimated that more than 95 percent of all Snake River juveniles may have been killed passing through turbines before reaching the lower Columbia River below Bonneville Dam (Haas, et. al., 1979). 13/

During low-flow conditions, juveniles can be greatly delayed by the relatively slack water of consecutive mainstem reservoirs. In addition to mortalities associated with increased exposure to predators within the reservoirs, many fish either lose their urge to migrate or are delayed to the point of being unable to make the physiological adaptation from fresh to salt water (Corps, 1980). 2/ This condition becomes more prevalent as the system is further developed to reduce the magnitude of the spring runoff through manipulation of upstream storage reservoirs.

Adult salmon and steelhead suffer similar mortality and stress as they negotiate the series of mainstem dams leading to their natal areas. Adult mortality is more dependent on species, dam, and flow, but still is estimated to vary from 5 to 25 percent per dam (Chaney, et. al., 1976 and 1978) 3/ 8/. A recent publication by the North Pacific Division, Army Corps of Engineers, entitled "Fifth Progress Report on Fisheries Engineering Research Program 1973-1978" (Corps, 1979) 14/, identified delay and fallback as the most serious problems facing adult migrant salmon and steelhead. This publication also summarizes all Corps research on this topic for the years 1973-1978. It is interesting to note that while high river flows benefit juvenile migrants by reducing passage time, these same high flows increase delays and cause higher levels of fallback for adults. Nitrogen supersaturation has also caused significant mortality to adult salmon and steelhead, but as indicated earlier, mortalities have now been reduced and controlled.

Excluding those mitigation measures associated with the construction of hydroelectric dams, there currently exist many cooperative efforts aimed at preserving and enhancing Columbia River salmon and steelhead. On a regional basis, the Pacific Northwest Regional Commission, the Pacific Northwest River Basin Commission, and the Pacific Fisheries Management Council have been developing strategies and coordinating efforts to benefit both the fisheries resource and its user groups.

Recently, the Washington State Department of Ecology published and adopted its Columbia River Instream Resource Protection Program (WA DOE, 1980). 4/ Through this program the State of Washington specifically seeks to provide minimum streamflows for fisheries protection in those areas of the Columbia River within the State's jurisdiction.

An ongoing effort to be completed before the end of 1980 is the Columbia River Fisheries Council's Joint Operational Plan (CRFC, 1978). 15/ This Plan is a two-part effort that was initiated with the publication of Phase 1 - Strategic Plan on March 23, 1978. The second phase is operational planning, which is intended to provide specific guidance for modifying individual and collective fishery agency operations to meet comprehensive planning goals.

On a day-to-day level, the Committee on Fishery Operations (COFO) serves as the forum for recommendations and agreement on river operations to protect juvenile and adult migrant salmon and steelhead. This ad hoc committee of the Columbia River Water Management Group is composed of representatives of the river operating agencies and utilities, Pacific Northwest Federal and State fishery management agencies, a representative of the Pacific Northwest Treaty Indian Tribes, and other governmental regulatory bodies. Since 1979, the COFO has developed and followed an "Implemenation Plan" for the juvenile migration season, which has been instrumental in the development of flow and spill levels beneficial to fishery survival (juveniles), while allowing the greatest operating flexibility for the hydroelectric generating system (Columbia River Water Management Group, 1980). 16/

Since Fiscal Year 1978, BPA has funded research aimed at protecting and enhancing the Columbia River salmon and steelhead resource while improving the operating flexibility of the Federal Columbia River Power System and ultimately benefiting BPA ratepayers. At the completion of Fiscal Year 1980, BPA will have expended approximately $3.3 million with an additional expenditure of $1.5 million programmed for Fiscal Year 1981. Research conducted under this program is submitted by the Columbia River Fisheries Council to BPA for approval, and then contracted by BPA directly to the fishery agency or entity identified by the Council as capable of carrying out the research effort.

BPA's role in funding fisheries research is only a small part of the regional effort to protect and enhance the salmon and steelhead resource. The Corps of Engineers has expended over $220 million through October 1979 (Brigadier General R. W. Wells.) 17/. In addition, the Lower Snake River Compensation Plan for the four Corps of Engineer's dams on the Lower Snake River, is expected to cost over $160 million upon completion in the mid-1980's. The Corps has also funded over $24 million on fishery research through its Fisheries Research and Protection Program Technical Coordinating Committee. On the Mid-Columbia, the three public utilities have entered into two uncontested Settlement Agreements (commonly called "The 5-Year Plan") designed to address minimum flow requirements below Priest Rapids Dam, and improve migration conditions throughout the Mid-Columbia reach. The PUD's had previously committed a sizable amount of resources (both funds and time) to the fisheries issues through actual fish facility construction projects and research.

The results of recent cooperative efforts to protect juvenile and adult salmon and steelhead at mainstem dams have been encouraging. Corps funded studies on collection and bypass systems at Columbia and Snake River dams have shown that up to 87 percent of juveniles can be diverted away from the turbines for successful passage around the powerhouse (Corps, 1979). 14/ Bypass systems under study include: traveling screens which collect and bypass fish into gatewells; bar screens; use of ice and trash sluiceways as surface collectors; turbine manipulation in conjunction with various controlled spill levels; and refinement of the various fish collection and bypass facilities at existing projects (Corps, 1979). 14/

Another area of promise deals with the juvenile transportation program (Corps, 1979). 14/ Since 1977, fish collected at Little Goose and Lower Granite dams on the Snake River have been transported by barge or truck for release below Bonneville Dam. As a result, all fish transported in this manner are not subjected to the rigors of passage at each dam and do not suffer delay in their migration to the sea. Although evaluations are not complete at this date, the Columbia River Fisheries Council in a letter to the Corps of Engineers, dated February 28, 1980, indicated that transportation was a worthwhile endeavor and should be continued on an interim basis until safe passage is achieved.

Beginning with the low water year of 1977, river flows have been manipulated and water has been spilled to enhance the passage of naturally migrating juvenile salmon and steelhead. The basis for flow and spill requests is presented in the Columbia River Fisheries Council's, "Rationale for Instream Flows for Fisheries in the Columbia and Snake Rivers" (Haas, et al, 1979). 13/ A summary of each spring's effort to enhance flows and spills may be found in the annual reports of the Committee on Fisheries Operation (Columbia

River Water Management Group, 1977 and 1978 and 1980). 6/ 7/ 16/ Results of these efforts will not be known until adults return from each group of migrants afforded flow and spill protection.

A final area of concern to management agencies has been the impact on spawning adults and their incubating eggs in the remaining natural spawning areas in the mainstem Columbia and Snake Rivers. Rapid tailwater fluctuations associated with hydro peaking operations result in adults being driven away from potential spawning sites, redds being dewatered and subjected to dessication and predation, and the emerging fry and juveniles being stranded as water levels decrease (Bauersfield, 1978). 18/

Footnotes

1/ National Marine Fisheries Service, 1979. Estimated Annual Contribution and Value of Fish of Columbia River System to the Pacific Ocean and Columbia River Fisheries Based on Latest 3-Year Average Sport and Commercial Harvest. Table prepared by the Environmental and Technical Service Division of the National Marine Fisheries, Portland, Oregon.

2/ U.S. Army, Corps of Engineers, 1980. Columbia Basin Water Withdrawal Environmental Review. Appendix D - Fish (Part I, Columbia River and Part II, Snake River), Portland, Oregon.

3/ Chaney, Ed and Perry, L. Edward, 1976. Columbia Basin Salmon and Steelhead Analysis. Report and supporting analysis were funded by the Pacific Northwest Regional Commission.

4/ Washington State, Department of Ecology, 1980. Columbia River Instream Resource Protection Program. Program Document, Environmental Impact Statement and Proposed Regulation for insuring the future viability of instream resource values of the mainstem of the Columbia River, Olympia, Washington.

5/ Oregon Department of Fish and Wildlife and Washington Department of Fisheries, 1979. Columbia River Fish Runs and Fisheries, 1957-1978. Joint staff recommendation for managing commercial fisheries of the Columbia River, Portland, Oregon.

6/ Columbia River Water Management Group, 1977. Special Drought Year Operation for Downstream Fish Migrants. Committee on Fishery Operation Annual Report for 1977, Portland, Oregon.

Production and Management of Columbia River Basin Anadromous Fish, Phase I - Strategic Plan, Portland, Oregon.

7/ Columbia River Water Management Group, 1978. Committee on Fishery Operations Annual Report - 1978, Portland, Oregon.

8/ Chaney, Ed, 1978. A Question of Balance. Produced under grant agreement with the Pacific Northwest Regional Commission.

9/ Bonneville Power Administration, Role Environmental Impact Statement.

10/ Bell, Milo C. and DeLacy, Allen C., 1972. A Compendium on the Survival of Fish Passing Through Spillways and Conduits. Prepared for U.S. Army, Corps of Engineers, North Pacific Division, Contract No. DACW 57-67-C-0105.

11/ Long, C. W., Krema, R. F., and Ossiander, F. J., 1968. Research on Fingerling Mortality in Kaplan Turbines - 1968. Bureau of Commercial Fisheries Bio. Lab., Seattle, Washington.

12/ Long, C. W., Ossiander, F. J., Ruhle, T. E., and Matthews, G. M., 1975. Survival of Coho Salmon Fingerlings Passing Through Operating Turbines With and Without Perforated Bulkheads and of Steelhead Trout Fingerlings Passing Through Spillways With and Without a Flow Deflector. National Marine Fisheries Service, Northwest Fisheries Center, Seattle, Washington. Final Report for Contract No. DACW 68-74-C-0113 to Army Corps of Engineers, Portland, Oregon.

13/ Haas, J. B. and Junge, C. O., 1979. Rationale for Instream Flows for Fisheries in the Columbia and Snake Rivers. Columbia River Fisheries Council, Portland, Oregon.

14/ U.S. Army, Corps of Engineers, North Pacific Division, 1979. Fifth Progress Report on Fisheries Engineering Research Program, 1973-1978. Summary of research funded by Corps of Engineers for the protection of anadromous fish, Portland, Oregon.

15/ Columbia River Fisheries Council, 1978. Comprehensive Plan for Production and Management of Columbia River Basin Anadromous Salmon and Steelhead. Phase I - Strategic Plan, Portland, Oregon.

16/ Columbia River Water Management Group, 1980. 1979 Annual Report - Committee on Fishery Operation, Portland, Oregon.

17/ Letter from Brigadier General R. W. Wells, Division Engineer, North Pacific Division, U.S. Army Corps of Engineers, to Ray Foleen, Deputy Administrator for the Bonneville Power Administration.

18/ Bauersfield, Kevin, 1978. The Effect of Daily Flow Fluctuations on Spawning Fall Chinook in the Columbia River. State of Washington, Department of Fisheries, Technical Report No. 38.

b. Riparian Wildlife.

The following is a description of the major direct and indirect impacts on riparian wildlife resulting from a continuation of the present level of daily and weekly tailwater and reservoir fluctuations controlled by the Federal Columbia River Power System (FCRPS) and Mid-Columbia PUDs as they are presently understood (Role DEIS: A, III.A). Further examinations of these fluctuations are currently being undertaken by Federal, State, and local resource agencies.

Water level fluctuations or the increased periodicity and amplitude of water levels associated with hydro peaking appear to have their greatest influence on wildlife indirectly through effects on wildlife habitat. This can occur in three ways. First, any impacts on prey or browse species will have a corresponding impact on other wildlife species. For example, 1980's water level fluctuations could cause avulsion adversely affecting shoreline vegetation which may affect deer and elk dependent on riparian browse, smaller mammals and birds dependent on aquatic insects or other riparian invertebrates, waterfowl dependent on aquatic vegetation or invertebrates for food, and mammals and birds dependent on fish for food. This impact is especially important if it occurs at a critical time of the year, such as when deer and elk are in wintering areas or waterfowl are migrating or nesting.

Second, any erosion of islands used for nesting by birds and fawning by deer, or shorelines used by reptiles for egg deposition, would decrease availability of habitat. This is most significant on small islands where such areas might already be in short supply.

And, third, during low water periods, land bridges may be formed to river islands allowing predators easy access to habitat that would otherwise be insulated. This impact is a concern a few months of the year when nesting and fawning is occurring, or when migratory birds are using the islands as resting places. However, effects can be long-term if substantial predation occurs during the breeding seasons. Measures to mitigate the impact of water level fluctuation should include maintaining adequate water levels to prevent the formation of land bridges.

Peaking operations may also have direct adverse impacts on wildlife. For example, drowning can occur when rapidly rising water inundates beaver and muskrat dens with young present, or bird nesting and deer fawning islands with chicks and fawns present, or when reptiles in estivation or hibernation are near the low water levels. Bank sloughing caused by erosion could destroy nests of such species as swallow and kingfisher and rapidly dropping water levels could strand and dessicate amphibian egg masses.

The long-term effects of changes in hydro peaking operations on rare, threatened, and endangered species and their critical habitats are relatively unknown, although studies are currently underway to examine these effects.

The bald eagle (Haliaeetus leucocephalus), classified as endangered in Idaho and Montana, and threatened in Oregon and Washington, depends mostly on fish for food. The long-term effects of hydro peaking operations on bald eagles are unknown. The Corps of Engineers and BPA are conducting studies to determine feeding, roosting, and perching behavior of eagles and their relationship to the operation of FCRPS facilities. Detrimental effects are possible if changed operations decrease accessibility of food fish. Also, elimination of habitat, such as perching trees, would be an adverse effect.

The American peregrine falcon (Falco peregrinus anatum), an endangered species, lives along the Columbia and Snake Rivers, but is not limited to riparian areas. Hydro peaking operations are not expected to affect this species.

The Columbian white tailed deer (Odocoileus virginianus leucurus) has been designated an endangered species in Oregon and Washington. A population of 400-500 individuals is located near Cathlamet, Washington, on the Columbia White-tailed Deer National Wildlife Refuge. Since riparian habitat is critical to this species, any adverse impact to the habitat would have a similar impact to the deer. However, because the refuge is located a considerable distance downstream from the hydroelectric facilities, impacts to this habitat and to the deer are not expected to be noticeable. Of equal, and in some cases even greater, concern here would be the impact to this habitat as a result of tidal fluctuations, commercial and recreation navigation, and intensive human use of the area.

In summary, hydro peaking operations can result in significant fluctuations in water levels which would have an adverse impact where the primary need of wildlife and vegetative communities is stability of flow. Accordingly, effects or results of these operations have their greatest impact on riparian habitats and those species dependent on this habitat type.

The reader is referred to the following reports for additional information on wildlife habitat, species, and impacts from hydro peaking: U.S. Army Corps of Engineers, North Pacific Division (1976), "Inventory of Riparian Habitats and Associated Wildlife Along the Columbia and Snake Rivers," Volume I; U.S. Army Corps of Engineers, NPD, Portland District (1972), "Modification for Peaking, Dalles to Vancouver, Columbia River, Oregon and Washington," Chapter 3, pp. 4-8; and Stanford Research Institute (1971), "Bonneville Environmental Impact Study," pp. 142-144, prepared for the Corps of Engineers, Portland District.

c. Water Quality.

Water quality in the Pacific Northwest generally is better than in most other areas of the country. However, as the area has developed, significant water quality problems have emerged.

Water quality has been a continuing concern in the Columbia River Basin since the turn of the century. In the Pacific Northwest there has been massive expansion of agriculture, especially irrigated areas; industry, including lumber, and electrochemical processing; recreation, including waterborne sports, hunting, fishing, camping, and hiking; construction of multipurpose dams that now utilize most of the head in the systems, changing most of the major rivers from free flowing to a series of stairstep lakes; and construction of thermal powerplants. Water temperature, eutrophication, dissolved oxygen levels, and, more recently, nitrogen supersaturation, all have been problems associated with development of the Columbia and Snake River Basins. See the Role DEIS (A: III.A.4) for additional details.

Dams and their reservoirs have also helped to reduce turbidity on the mainstem Columbia. The reduced flows in reservoirs allow the settling of suspended material. However, this same condition has resulted in the settling of aggregate and has reduced or completely eliminated the recruitment of aggregate downstream.

Additional turbines at FCRPS and mid-Columbia PUD projects generally should enhance water quality. Added units would materially increase deep water outflow capacity, greatly reducing spills. This, in turn, would reduce the water temperature mix below the project and minimize gas supersaturation.

The increased turbine outflow could increase dissolved oxygen from deep reservoirs under some low flow conditions. However, this has not been a major problem in most areas and should not be with the developing Federal and non-Federal hydro system.

2. Socioeconomic Systems.

a. Commercial, Sport, and Indian Fisheries.

Traditionally, the fisheries resource and its related recreational and commercial industries have ranked high as a source of income to the States within the Columbia River basin. The historical development and growth of these States has been closely aligned with the harvest of anadromous salmon and steelhead trout using the Columbia River and its tributaries.

The development of the Columbia River hydro resource has resulted in reduced availability of this fishery resource. Once important commercial and Indian river fisheries have been reduced to token levels as upper river runs of salmon and steelhead have declined. Individuals utilizing this resource have been forced to redirect their activity to other fisheries or change their life styles by finding other sources of income. Likewise, due to increasing pressure on the fishery resource, commercial activity in the ocean is facing more restrictive regulations, reducing harvest and shortening seasons. New regulations may limit access to the fishery. Sport fishing has been seriously jeopardized by reductions in fish populations and faces probable curtailment.

b. Recreation.

Facilities that comprise the hydroelectric power and storage system in the Pacific Northwest have transformed swiftly flowing rivers into over 190 stairstep reservoirs. Few free flowing reaches remain (Role DEIS: A, VII-136).

Reservoirs offer a broad range of water recreation opportunities, including swimming, boating, fishing, water skiing, skin diving, and waterfowl hunting. Federal, State, and local agencies, and private companies have developed more than 290 recreation sites on adjacent lands to satisfy the existing recreational demand on the Columbia and Lower Snake Rivers.

Recreational activity is directly related to management of the reservoirs for other uses, such as power generation, flood control, irrigation, and navigation. Control of the water resource to optimize these operational goals significantly affects the quality of recreation on the reservoirs. Operational effects on recreation can be grouped under three causative factors: drafting and filling reservoirs, water level fluctuations, and flow rate variations. The first factor, drafting and filling reservoirs, is most common on major storage reservoirs such as Grand Coulee, Libby, Hungry Horse, and Dworshak. Operation of pondage plants, which comprise most of the remainder of the system, creates effects related to the second factor, fluctuation. Varying flow rates could affect the recreational use of all system reservoirs.

(1) Storage Reservoirs.

Recreational activities on these impoundments coincide with the seasonal pattern of draft/refill. Peak use of the impoundments for recreation takes place during June, July, and August, when water levels generally are high. (Land use impacts of regional hydroelectric facilities are shown in Table IV-47.)

Though pool elevations behind storage dams normally are high during the peak-use summer months, situations can develop which adversely affect recreation. In years when flows are low, reservoirs may not fill and subnormal water levels may be experienced during the peak recreation period. These impacts would be further amplified by drafts needed to satisfy provisional storage commitments. Beneficial and detrimental effects on power and nonpower interests are discussed between BPA and the reservoir operators prior to making provisional commitments. Under low water conditions, bare gravel or mud slopes are exposed to view. Many fixed facilities such as boat launch ramps and marinas become inoperative. Fishermen's access to the water by boat or from the shore is severely impaired. Boaters face increased hazards due to unmarked shoals or bars close to the surface. Secondary effects on recreation can be created by the inability of fish or wildlife to maintain normal life cycles.

(2) Pondage Projects.

As with storage dams, generally the greatest operational demand is experienced during the winter, when recreation subsides to its lowest level. However, daily or weekly fluctuations have affected present recreational uses. Many public recreation facilities were designed initially for a specific water level. If the pool goes below that level, the installation is no longer operational. This situation has been encountered at swimming beaches, boat launches, and moorages. A change in water level can alternately strand or flood some river islands and beaches. Boats can be damaged or lost by being beached or set adrift. Pools with bars or shoals close to the surface cannot be utilized for boating. Recreational use of undeveloped areas may also be impacted.

Water released at FCRPS projects to produce power at-site or downstream causes fluctuations in reservoir levels and streamflows on free flowing stretches of rivers below some of the dams. The fluctuations caused by the existing system do not always impact recreation adversely. However, tailwater changes cause concern with regard to safety of recreationists downstream from Grand Coulee, Bonneville, Dworshak, and Chief Joseph dams. These fluctuations level out and disappear as the water moves downstream.

(3) Peaking Unit Additions.

Peaking unit additions to the FCRPS and Mid-Columbia public agency projects will result in greater and more rapid fluctuations in flows and reservoir levels. Increased river fluctuations caused by hourly peak demands could be damaging to recreational uses. Care must be taken to minimize difficulties encountered by recreational users due to cyclic water level changes, especially below power projects. Rapid changes in water levels could further endanger boaters and people using shorelines for camping and fishing.

(4) Provisional Storage Operations.

FCRPS projects can be operated to supply provisional, power to industries and utilities. The operation of a reservoir to supply advance power means it will be drafted below its normal operating limit--usually early in an operating year. The recipient of the power guarantees to return energy equivalent to the drafted water if refill is not otherwise accomplished. Drawdowns to provide relatively small amounts of provisional power can be accomplished without significant adverse effects on recreational activities by distributing the amount of drawdown among several reservoirs. Supplying large amounts of provisional power could incur significant adverse impacts at Hungry Horse, Libby, and Dworshak reservoirs late in the recreational season (Role DEIS: A, III-137-140, III-182-184).

c. Visual and Esthetic Values.

The hydroelectric resources of the Pacific Northwest occupy sites which vary greatly with respect to topography, climate, vegetation, adjacent land uses, etc. Their initial installation greatly altered the existing appearance of the sites by flooding land for reservoirs, changing free flowing streams with rapids and falls into placid bodies of water, and establishing structures such as dams, powerhouses, and transmission towers. The greatest change in appearance of the landscape occurred with the initial installation of these facilities. Further visual changes have occurred since and are still occurring as a result of facility expansions or alterations, such as the third powerhouse at Grand Coulee and the second powerhouse at Bonneville Dam. Operations resulting in fluctuating reservoir levels have relatively minor effects on the appearance of the hydroelectric resources, although lower water levels expose other views of the environment. Immersed rocks, snags, shoals, mud flats, and sandy-silt covered bottoms of reservoirs become apparent. Dredge spoils and various types of disposal also may be seen near dams.

d. Cultural Resources.

Areas along major Pacific Northwest rivers contain rich historic archeological artifacts of early inhabitants. Lifestyles of some of the early civilizations are detailed in the environmental statement for the Columbia Basin Project (USDI, Bureau of Reclamation, 1976). Various sites of historic value have been identified in the U.S. Army Corps of Engineers "Columbia River and Tributaries Review Study" (1975b, 1975c, 1975d, and 1975e). Facilities currently being developed will produce some impacts on the identified sites (Role DEIS: A, III-187 and 188).

Archeological inventories and selected salvage were accomplished before construction of present hydroelectric facilities. Most of the reservoir areas were subjects of Smithsonian Institution River Basin Surveys and many have since been resurveyed by various Pacific Northwest universities and other agencies. However, many archeological sites have been destroyed by construction and reservoir fluctuations with resultant erosion, deposition, and landslides.

Inundation does not necessarily destroy archeological sites, although it does render them inaccessible. Submersion does not greatly alter site contents, but does create problems in interpretation since chemical precipitates are absorbed into the soil profile (Role DEIS: A, III-148). In addition, siltation presents a long-range problem of accessibility, obscuring site location.

The Corps of Engineers concluded that alternately raising or lowering pond levels could cause serious sloughing problems for some sites through frequent saturation and drying. Increased erosion, placing riprap along the banks, and blasting to obtain riprap could impact additional archeological sites. Raising pond levels would also increase accessibility to some perched sites, thereby increasing the risk of vandalism.

Increased fluctuations in reservoir levels, resulting from planned use of the FCRPS to meet greater amounts of hourly peak loads, could lead to increased erosion at archeological sites near the shores of the reservoirs, although this impact is probably minor because of the damage to the sites which has already taken place.

Archeological resources have been surveyed through contracts with constructing agencies at each of the facilities currently undergoing expansion. The agencies assume the responsibility for protection, salvage, or destruction of identified archeological sites. The constructing agency makes a detailed analysis of the facility impacts prior to construction. This analysis includes consideration of properties listed in or eligible for inclusion in the National Register of Historic Places. Subsequently, National Advisory Council on Historic Preservation procedures for their protection are followed.

e. Irrigation.

The significant impacts to irrigation fall into two categories: (1) effects of reservoir level changes on existing irrigation pumping facilities; and (2) effects of tradeoffs between potential hydroelectric generation and expanded irrigated agriculture.

Some intake elevations for irrigation pumps are currently too high to operate when reservoirs are down, especially in the upper Columbia basin. For example, the raising of Lake Rufus Woods' pool by 10 feet should reduce irrigation pumping problems there. The changing flow patterns are not expected to create any additional problems elsewhere in the Basin.

The impact of peaking unit installations on future expansion of irrigated agriculture in the Columbia Basin will depend principally on water allocation and management decisions affecting both power operations and irrigation withdrawals. Irrigation requires both large amounts of water and electricity for pumping. Completion of peaking installations currently under construction will enable the FCRPS and non-Federal project owners to utilize most of the available flows to generate electric power, which would limit the potential expansion of irrigated acreage. However, tradeoffs are likely between generation and irrigation water needs, as well as between these two and minimum flow requirements for fisheries and water quality maintenance.

Thus, full utilization of the hydroelectric facilities now under construction constitutes a potential opportunity cost to additional crop production on irrigated land, but the magnitude of that impact is dependent on the ultimate tradeoffs yet to be determined between alternative regulations and allocations of the available water.

f. Navigation.

Flow pattern changes under the developing system should have little effect on river stages below St. Helens (RM 86.0) as the tides generally have a controlling effect on the river. Oceangoing vessel traffic in the Lower Columbia River area would not be impacted by the developing system.

There are larger concentrations of port facilities, moorages, and log rafts below Bonneville along the main stem and in the Portland-Vancouver area. Continued access to these facilities during low stages associated with the developing system could require increased maintenance dredging. Similar facilities are scattered along the Columbia and Lower Snake Rivers. Low stages could restrict access to industrial facilities, plywood mills, log ponds, loading and unloading facilities, and moorages, and in come reaches could expose shoals and rocks and drop water levels in navigation channels below authorized depths.

Low stages would create definite navigation problems in rock and shoal areas and navigation channels. Stages below projects on the Lower Snake and Mid-Columbia Rivers experienced with median and high flows under the mid-1980's operation would be lower than those now experienced. Problems at some navigation lock approaches due to high velocity would be accentuated by changing power flow patterns.

g. Community Services.

The primary community services impacts associated with hydro facilities in the Hydro-Thermal Power Program (HTPP) would result from construction-induced population increases. Increased demands have been or will be placed on local municipal services (schools, police and fire departments, health care agencies, etc.). Although some additional social service provisions would be required by permanent operations and maintenance personnel at each facility, the number of persons involved is small relative to the construction force.

Several factors may make it difficult for communities to effectively provide the rapid increases in social service levels generally required to meet the demands of construction workers. In the case of the HTPP hydro projects, the communities involved are relatively small and may experience some financial stress in meeting the cost of service expansions. Also, since construction booms last for relatively short periods of time, the required adjustments in available facilities must be made with the realization that permanent expansion may not be justified. Finally, in most cases there is a lag between the need for additional tax revenues and the collection of those revenues. Transient construction workers would make minimal contributions to the property tax bases of impacted communities, and the contributions derived from permanent operation and maintenance staffs would develop subsequent to the construction period (Role DEIS: A, III-185-187).

The introduction of significant numbers of construction workers may be viewed as disruptive of community lifestyles if the incomes, recreational patterns, and housing requirements of the construction force differ significantly from predominant community characteristics.

(2) Thermal System.

(a) Description of the Thermal System.

1. Description and Status of Projects: Hydro-Thermal Power Program (HTPP).

Table IV-3 lists those projects associated with the HTPP. Projects which are completed, under construction, or committed are identified. Committed projects are those that are planned for construction by utility sponsors in the region, but have not yet received licenses, permits, or authorizations to proceed with construction. Of the projects committed subsequent to Phase 1 of the HTPP two have been completed, six have been authorized and are under construction, and six remain in the 'committed' and 'proposed' category.

In addition to the site-specific information given below, the reader is referred to the impact information given in Tables IV-48, IV-49, and IV-50.

TABLE IV-3

THERMAL POWERPLANTS
July 1980

Plant	Location	Principal Sponsors 1/	Fuel	Total Capacity, MW	On-Line Date
In Operation					
Hanford Generating Plant	Hanford, WA	WPPSS	Nuclear	860	Nov 1966
Centralia No. 1 & 2	Centralia, WA	PP&L & WWP	Coal	1,400	Aug 1971
Jim Bridger No. 1, 2, & 3	Rock Springs, WY	PP&L & IPCo	Coal	1,500 2/	Oct 1975, Sept 1976
Colstrip No. 1 & 2	Colstrip, MT	TMPCo & PSP&L	Coal	660 2/	Nov 1975, Aug 1976
Trojan	Rainier, OR	PGE	Nuclear	1,130	Dec 1975
Jim Bridger No. 4 3/	Rock Springs, WY	PP&L & IPCo	Coal	500 2/	Dec 1979
Boardman (Carty) 3/	Boardman, OR	PGE	Coal	530 2/	Jul 1980
Under Construction					
Whitehorn No. 2 & 3 3/	Ferndale, WA	PSP&L	Gas/Oil	176	Nov 1980
WNP No. 2	Hanford, WA	WPPSS	Nuclear	1,100	Jan 1983
WNP No. 1	Hanford, WA	WPPSS	Nuclear	1,250	Jun 1985
WNP No. 3	Satsop, WA	WPPSS	Nuclear	1,240	Jun 1986
WNP No. 4 3/	Hanford, WA	WPPSS	Nuclear	1,250	Jun 1986
WNP No. 5 3/	Satsop, WA	WPPSS	Nuclear	1,240	Jun 1987
Committed					
Colstrip No. 3 & 4 3/	Colstrip, MT	TMPCo & PSP&L	Coal	1,400 2/	Jan 1984, Nov 1989
Columbia 1 & 2	Hanford, WA	PSP&L	Nuclear	2,576	Jul 1990, Jul 1992
Pebble Springs No. 1	Arlington, OR	PGE	Nuclear	1,260	Jul 1992
Pebble Springs No. 2 3/	Arlington, OR	PGE	Nuclear	1,260	Jul 1994
Proposed					
Kettle Falls 3/	Kettle Falls, WA	WWP	Wood	42	Jul 1983
Creston No. 1 & 2 3/	Creston, WA	WWP	Coal	1,000	Jul 1987, Jul 1989

1/ IPCo - Idaho Power Company
PGE - Portland General Electric Company
PP&L - Pacific Power & Light Company
PSP&L - Puget Sound Power & Light Company
TMPCo - The Montana Power Company
WPPSS - Washington Public Power Supply System
WWP - Washington Water Power Company

2/ No all of the output of these units is available to meet West Group Area loads. Capacity available to meet West Group Area loads from these units is as follows:

Jim Bridger No. 1, 2, & 3	1000 MW
Colstrip No. 1 & 2	330 MW
Jim Bridger No. 4	333 MW
Boardman	477 MW
Colstrip No. 3 & 4	980 MW

3/ Plants considered subsequent to Phase 1 of the Hydro-Thermal Power Program.

a. Plants in Operation.

(1) Hanford Generating Plant HGP).

The steam supply source for Hanford is the N Reactor, or New Production Reactor (NPR), owned by the U.S. Department of Energy (DOE). The HGP, owned by the Washington Public Power Supply System (WPPSS) consists of two 430 MW turbine-generators. The HGP is on the Hanford Nuclear Reservation adjacent to the Columbia River near Richland, Washington.

(2) Centralia Coal-Fired Plant.

This plant consists of two 700 MW units in the Hanaford Valley about 5 miles northeast of Centralia, Washington. The plant is a mine-mouth operation, with a short haul between the coal strip mine and plant. All coal from the mine is used at the plant site. The combined plant and mine area is approximately 16,000 acres.

(3) Trojan Nuclear Plant.

This single unit, 1,130 MW pressurized water reactor (PWR) plant is on the Oregon side of the Columbia River near Rainier. The closed-loop cooling system utilizes a natural draft cooling tower, with makeup water taken from the river. The total land area occupied is 634 acres.

(4) Jim Bridger No. 1, 2, and 3.

The Jim Bridger coal-fired steam electric generating project, located 35 miles east of Rock Springs, Wyoming, is owned by Pacific Power & Light Company (PP&L) and Idaho Power Company (IPC). Each unit is rated at 500 MW.

Coal is furnished to the plant from the Jim Bridger coal field, which is located 3 to 10 miles from the plant. Water for the plant has been purchased from the State of Wyoming, which has municipal and industrial water in the Bureau of Reclamation's Fontenelle storage project on the Green River. PP&L receives two-thirds of the generation and IPC one-third.

(5) Colstrip No. 1 and 2.

Puget Sound Power & Light Company (PSPL) and The Montana Power Company (TMPCo) are joint sponsors of a mine-mouth coal-fired generating plant located at Colstrip in eastern Montana. Half of the output of the two initial 330 MW units goes toward meeting PSPL's load, and the balance serves The MPC load.

(6) Jim Bridger No. 4.

Subsequent to Hydro-Thermal Power Program Phase 1, studies were made on the feasibility of adding a fourth 500 MW coal-fired unit at the Jim Bridger plant site which is located near Rock Springs, Wyoming. Approval for construction was received from the Wyoming Public Utilities Commission late in 1975. The unit includes a flue gas desulfurization (FGD) system for control of SO_2 emissions to meet Wyoming State standards. Generation from this unit is shared between the two sponsors, with PP&L's share being two-thirds and Idaho Power Company's share one-third.

(7) Boardman (Carty) Coal.

In March 1975, Portland General Electric Company received a site certificate from the State of Oregon permitting construction of a 530 MW coal-fired plant located 12 miles southwest of Boardman, Oregon. The plant started up on July 12, 1980; first reached full power on July 25, 1980; and became commercially operable on August 3, 1980.

Idaho Power Company is a 10 percent owner and Pacific Northwest Generating Company has signed with PGE for a 10 percent share. The fuel used to fire the plant is low-sulphur subbituminous coal, which is transported by rail from Gillette, Wyoming. A reservoir was developed at the plantsite for the water for both plant cooling and irrigation.

b. Plants Under Construction.

(1) WPPSS Nuclear Project No. 2.

WNP-2 is located on the Hanford Reservation, with a net output of 1,100 MW. The project is being constructed and will be owned and operated by the Washington Public Power Supply System (WPPSS). The project has 94 participants who have contracted with WPPSS for the project output and assigned it to BPA under net-billing agreements. The participants are all statutory preference customers of BPA and at present obtain all or part of their power supply from BPA. The plant has a boiling water reactor and mechanical draft cooling towers.

Construction of WNP-2 was 84 percent complete as of May 1, 1980. The probable energization date is January 1983. Project costs have increased from the 1978 estimate of $1.077 billion to the revised 1979 estimate of $1.734 billion, including debt service.

(2) WPPSS Nuclear Project Nos. 1 and 4.

Washington Public Power Supply System Nuclear Projects No. 1 (WNP-1) and No. 4 (WNP-4) are duplicate 1,250 MW powerplants on the Hanford Reservation. Each plant will use a pressurized water reactor to run a turbine-generator and will have mechanical draft cooling systems to dissipate heat from the turbine condenser cooling system. WNP-1 was 40 percent complete as of May 1, 1980 and has a probable energization date of June 1986. WNP-4 was 16 percent complete as of May 1, 1980 and has a probable energization date of June 1986. BPA will obtain the output of WNP-1 under net-billing and exchange agreements. Output from WNP-4 is under contract to 88 preference customers (not net-billed).

(3) WPPSS Nuclear Project Nos. 3 and 5.

WPPSS Nuclear Projects No. 3 and No. 5 (WNP 3 and WNP 5) will be twin facilities, each with a pressurized water reactor to run turbine-generators rated at 1,240 MW. The plants will use hyperbolic, natural draft cooling towers for cooling the condenser. The plantsite is in Grays Harbor County, Washington.

WPPSS is 70 percent owner of WNP-3, with the remaining 30 percent owned by four investor-owned utilities: PGE (10 percent), PP&L (10 percent), PSPL (5 percent), and WWP (5 percent). WPPSS's portion of the electrical output of WNP-3 will be purchased by 103 consumer-owned utilities and assigned to BPA under net-billing.

WNP-5 will be jointly owned with PP&L which will have a 10 percent share. There will be 88 consumer-owned utilities sharing WPPSS' portion of the power (not net-billed). WNP-3 was 22 percent complete as of May 1, 1980 and has a probable energization date of June 1986. WNP-5 was 10 percent complete as of May 1, 1980 and has a probable energization date of June 1987.

(4) Whitehorn No. 2 and 3.

These units will be combustion-turbine (C-T's) rated at 89 MW each. Preliminary site work is underway. However, the fuels for these C-T's are oil and gas, so an exemption from the Fuel Use Act (FUA) is required before further construction can proceed. Therefore, major construction has proceeded as far as possible until the FUA permit is received. This may delay the probable energization date of November 1980. The owner, Puget Sound Power & Light Company has an option to purchase two more units. The additional units might be scheduled for energization as early as November 1981.

(5) Colstrip No. 3 and 4.

These additional units at Colstrip Project are sponsored by The Montana Power Company, Puget Sound Power & Light Company, Portland General Electric Company, Pacific Power & Light Company, and Washington Water Power Company. The project consists of two 700 MW coal-fired electric generating units located at Colstrip, Montana; continued development of coal resources at Colstrip; and a water supply system consisting of a 29 mile underground pipeline from an existing intake structure at Nichols, Montana, to the existing surge pond (Castle Rock Lake). The probable energization date for Unit 3 is January 1984 and Unit 4 is November 1984. Unit 3 was 3 percent complete and Unit 4 was 1 percent complete as of April 1980.

c. Committed Plants.

(1) Columbia 1 and 2.

The Columbia Nuclear Power Project consists of two generating units, each with an output of 1,288 MW. These plants will be located at the Hanford Reservation, Washington. Water for the closed-cycle cooling system will probably be pumped from Columbia River. Cooling towers probably will be associated with each generating unit and will discharge most of the heat rejected from the steam condenser to the atmosphere. Ownership of the Columbia Project will be shared by PSPL (40 percent), PP&L (20 percent), PGE (30 percent), and WWP (10 percent). Unit 1 has a probable energy date of July 1990, and Unit 2, July 1992.

(2) Pebble Springs 1 and 2.

The Pebble Springs Nuclear Power Project is located close to Arlington, Oregon, near the Columbia River. Each unit will have an output of 1,260 MW. A closed-loop cooling system is planned to utilize a man-made cooling lake with makeup water drawn from the Columbia River. Discharge will be to a large cooling reservoir. Unit 1 ownership is shared between PGE (42 percent), PP&L (26 percent), PSPL (21 percent), and others (15 percent). Unit 2 ownership is shared between PGE (47 percent), PP&L (29 percent), and PSPL (24 percent).

Project design is approximately 44 percent complete. The focus of activities is on obtaining the necessary State and Federal permits for construction. The Oregon Nuclear Thermal Energy Council recommended a site certificate to the

Governor in mid-1975. The site certificate was remanded to the Energy Facility Siting Council by the Oregon Supreme Court in March 1977.

There has been considerable difficulty in obtaining a site certificate, resulting in a delay in scheduling, with tentative dates of July 1992 for Unit 1, and July 1994 for Unit 2. We understand there has been informal consideration of moving the site to the Hanford Reservation, Washington.

d. Proposed Plants.

(1) Kettle Falls.

The Kettle Falls plant is under active consideration by Washington Water Power Company near Kettle Falls, Washington. It would be a 42 MW wood-fired unit, with the fuel being wood waste from nearby mills. The tentative on-line date is July 1983.

(2) Creston.

Washington Water Power Company is actively pursuing a coal-fired plant near Creston, Washington. The company is preparing an Environmental Assessment Report and plans to apply for a site certificate in January 1981. The present plan is to license the site for up to 2000 MW, probably with 4-500 MW units. Unit 1 is tentatively scheduled to be on-line July 1987, and Unit 2 July 1989, assuming that the site certificate will be issued by June 1982.

2. Operation of the Thermal System.

The thermal portion of the region's power system consists of those large coal and nuclear plants listed in Table IV-3. In addition, there are a number of small, fossil fuel-fired generating plants, combustion turbines, and diesel generators which contribute to the region's electrical generating capacity and are addressed generically in this section (Role DEIS: 1, V-25-108). This section discusses operation of the thermal system as a whole.

a. Load Following Capability.

One of the fundamental differences from an operational standpoint between large thermal resources, such as the region's coal and nuclear plants, and hydro resources is the ability to rapidly vary a unit's output. Hydro units, as discussed in Section IV.A.l.a.(1)(a), can be operated to rapidly change output in order to meet varying loads. Large thermal plants, on the other hand, are efficiently and economically operated within a limited range of gradual output variation.

Continuous operation of large baseload, coal-fired thermal units near 80 to 100 percent of their maximum generation results in the most economical fuel use and troublefree performance. Varying their generation results in problems, including uneven thermal expansion in the turbine, excessive changes in temperatures and pressures within the boiler, problems in maintaining boiler combustion at lower loads, and marginal performance of stack emission control equipment. Limited coal storage facilities, combined with firm "take-or-pay" coal delivery contracts, may make load following uneconomical. Daily shutdown and startup cycles require long warmup periods which use considerable fuel without generating energy. In addition, there may be wear and breakage during startup, expensive oil will be burned to provide initial ignition, and the lifetime of pressure parts may be shortened drastically. In spite of these constraints, it appears that variation from 60 to 100 percent of maximum generating capacity, though uneconomical, is possible with large coal-fired thermal plants. Loading levels of 60 percent can be maintained without supplementary oil firing of the boiler to assure ignition. The minimum level of generation has to be determined for each unit by trial and error; however, most coal-fired baseload units probably can be operated by manual control at ratings down to about 40 percent of full load. At this level, the unit cannot respond to transient load conditions and is particulary vulnerable to tripouts.

Large nuclear plants may be even more limited than coal-fired thermal plants in their ability to vary output. In nuclear plants, as in coal-fired thermal plants, uneven expansion of the turbine would be a problem if plant generation were varied too quickly. A similar uneven expansion in the nuclear steam supply system would be likely to cause stresses in fuel assemblies and could result in leakage of radioactive material into the primary cooling loop. Nuclear plant generation may be changed between 85 to 100 percent of maximum generation over about a 6-hour period.

The combined effect of these operational characteristics of coal and nuclear plants is that, except for forced or planned outages, they are generally operated at or near full output. This places the burden of load following and meeting peak loads principally on those resources capable of rapidly altering output, namely, the region's hydro system, combustion turbines, and small thermal plants. As new large coal and nuclear plants come on line, this burden will increase, and, unless other means of load following or reducing load variability (e.g., energy storage systems, peakload management) are implemented, fluctuations in river flows and reservoir levels, and operation of combustion turbines and peaking thermal units will increase.

b. Planned Outages.

A second operational consideration with respect to the thermal subsystem is the need to shut down plants for maintenance and, in the case of nuclear plants, refueling. A general plan scheduling maintenance of generators of all systems within the Northwest Power Pool covered by the Pacific Northwest Coordination Agreement is developed each year as a part of the annual operating plan. Nuclear plant outages for refueling are included. Planned maintenance outages may range from a few days' duration to several weeks. Major overhauls of steam turbines and annual refueling at nuclear plants may require outages of 6 to 8 weeks. Maintenance of all components of a thermal unit, such as the turbine, boilers, and auxiliaries, and refueling of the nuclear reactor, usually proceed simultaneously. These annual operating plans provide a mechanism for coordinating planned maintenance outages to produce the least reduction of firm energy and peak capability of the pooled systems. Arrangements for maintenance and refueling of thermal units are complex and not very flexible.

When a large thermal unit is taken out of service for maintenance, the systems which have been receiving its generation must either reduce their power deliveries, increase their purchases, or increase the generation within their system to compensate for the loss. If only one system were involved, it would have to replace the entire loss. No single system in the Pacific Northwest is large enough to do this easily. In the case of most large thermal units existing or planned for the Pacific Northwest, two or more systems are receiving the generation from each large thermal plant. Therefore, the generation loss is divided among the systems involved and is easier to absorb.

c. Forced Outages.

Large thermal units, like other generating resources, are subject to "forced outages." Forced outages of generating units occur when failures of mechanical or electrical equipment require the units be taken out of service. Statistical records indicate thermal units are much more likely than hydro units to be forced out of service, and that the probability of thermal units being out of service because of a forced outage increases as unit size increases.

Forced outages create all of the problems associated with the loss of a unit's generation previously described in connection with planned maintenance outages. In addition, all of these problems must be handled on short notice.

The rates at which forced and planned outages occur for thermal plants are reflected in a quantity called "equivalent availability" or "capability factor", which represents the ratio of the maximum amount of energy which could have been generated if only forced and scheduled maintenance outages occurred, to the amount of energy which could have been generated if there were no outages of any kind. The PNUCC uses the following equivalent availabilities for planning purposes:

Coal	500 MWe	60%	First year of operation
		75%	Thereafter

These capacity factors are adjusted for each utility by a "realization factor" which allows each utility to reflect the energy availability that it considers appropriate.

Nuclear	60%	First year of operation
	75%	Thereafter

d. Forced and Planned Outage Reserve Requirements.

Because of the need to shut down thermal plants periodically for maintenance and the possibility that a plant may have a forced outage at any time, it is necessary to provide reserve (or backup) capacity to meet loads during these events. Thermal plants have greater reserve requirements than hydro units because of their greater requirements for maintenance and greater likelihood of forced outages. A forced outage at a large thermal plant can result in a sudden loss of a significant increment of power to the region's power supply system, which is much more difficult to make up than the loss of a small unit. For this reason, large thermal plants also have higher reserve requirements than do small thermal plants.

The Pacific Northwest Coordination Agreement provides for the delivery of power to back up a forced outage of any hydro or thermal unit. Such delivery is required of any system which at the time has less capacity forced out of service than the forced outage reserve computed for that system under the annual operating plan. This arrangement usually is impractical because of the difficulty in locating a system which meets the contractual conditions in the few minutes following a forced outage. When a forced outage occurs and the individual system is unable to cope with the generation loss by itself, it tries to locate any unused generation and acquire it on the best terms that can be arranged within the time available.

Backup to forced outages usually can be provided more easily by hydro generators than by thermal units because they are more capable of increasing their generation quickly and sustaining the increase for a few hours. Hydro units which are not spinning can be started and brought to full load within a few minutes, whereas it usually takes days to bring a large thermal unit from cold standby to full load. A conventional nuclear or fossil-fired thermal plant cannot be used to provide forced outage reserves unless its boiler or nuclear steam supply already has been brought up to operating temperatures. Of the commercially available alternatives, only combustion turbines are comparable to hydro units in their ability to provide operating forced outage reserves.

3. Coordination.

a. Need for Formal Thermal Coordination.

Some form of formal thermal resource coordination would result in improved regional operations. Independent operation of thermal resources causes utilities to install extra capacity and carry additional forced outage reserves. At present there are only a few large thermal plants operating in the Pacific Northwest. Some coordination of their operations has been achieved under provisions of the Pacific Northwest Coordination Agreement, but this Agreement is essentially directed at coordinated operation of hydroelectric projects. The two thermal plants that existed at the time the Agreement was written--Dave Johnston (in Wyoming) and Hanford--were not included.

Many difficulties have been encountered in subsequent application of Pacific Northwest Coordination Agreement planning methods to the Centralia, Trojan, and Hanford thermal plants. Arrangements for delivery of interchange energy to support thermal plant outages are lacking. Procedures for exchange of thermal energy on the basis of economy of operation are not provided for by the Agreement. Procedures for scheduling maintenance on hydro units cannot always accommodate thermal maintenance schedules.

A thermal coordination agreement would alleviate the problems listed above and could result in improvements in some additional areas of concern. Forced outage backup and backup to scheduled maintenance are subjects that need to be considered in an agreement. In general, efforts to allow parties to capitalize on existing diversities would benefit the region.

There appear to be several alternatives to a regional thermal coordination agreement. One alternative would involve the execution of a myriad of bilateral thermal coordination agreements between Northwest utilities. The ultimate, aggregate effect of bilateral agreements would be much the same as the effect of a single, multi-participant agreement, but administration would obviously be much more complex.

Another form of thermal coordination is that which would naturally occur if all thermal resource development and operation were assigned to a single entity. In broad terms, this type of arrangement can be viewed as the "maximal" level of thermal coordination. Because of the absence of competing interests and purposes, conflicts regarding resource displacement and maintenance scheduling that might otherwise occur could be resolved by the single developing/operating entity to maximum advantage.

b. Potential Impacts.

There would be some environmental impacts created by a thermal resource coordination agreement. Whereas such an agreement might facilitate the development of thermal plants, it might also reduce the amount of generating capacity needed to serve a given load, resulting in fewer environmental impacts than without such an agreement. If the region continues with a thermal base, minimum flow requirements would be affected. However, those impacts typically associated with operation of thermal plants are likely to be shifted or redistributed throughout an operating year. Operating without a thermal agreement, thermal plant owners prefer to shut down for refueling and annual maintenance during the high-streamflow spring months. This has the benefit of aiding juvenile salmon and steelhead migration by increasing river flows to generate the additional energy lost when thermal plants undergo annual maintenance. Additionally, air and water pollution is minimized during those months.

Under a thermal resource coordination agreement, scheduled plant outages would be better distributed throughout the year to maximize firm load carrying capability and to enable rotation of maintenance crews. Thermal plant operators would still make efforts to schedule as much maintenance as possible during the May-June high flow period. If insufficient hydropower were available to displace thermal resources for maintenance during this period, thermal coordination would provide support for maintenance outages during other times of the year. Some plants that would otherwise be shut down in the spring would instead be shut down during summer and fall, allowing the more efficient use of maintenance crews. Seasonal requirements for several crews to work simultaneously would be reduced. Addition of heat to the Columbia and Skagit Rivers and stack emissions in certain airsheds would be more nearly constant throughout the year due to coordination. However, during low runoff water years, this coordination may have an impact on juvenile fish migrations which require high water flows.

The cumulative plant capacity savings associated with coordination will lessen the need for development of other generating resources, resulting in fewer detrimental impacts on air and water quality from generating plants, and less commitment of land for generating plants. Construction of fewer generating plants will presumably have a beneficial effect on power rates and fuel supplies, but a negative effect on employment associated with manufacturing and installing generating facilities.

c. Hydro-Thermal Coordination.

(1) Baseload Thermal Growth.

Because few environmentally acceptable sites remain at which economically feasible large hydroelectric projects can be developed, the Pacific Northwest has begun to develop coal-fired and nuclear plants. Plants fueled by oil and natural gas are not feasible due to fuel supply problems, fuel costs, and national policies relating to natural gas regulations and foreign oil purchases. Large units generally have proven to be more economical to construct and operate than smaller units, provided their operating characteristics are acceptable to the system within which they are to be operated. Similarly, thermal units designed to operate at a constant output to serve baseload have been shown to be more economical than thermal units designed to vary output to match the changing load.

(2) Added Peaking at Hydroelectric Plants.

Using thermal units to meet the baseload, and operating existing and new hydroelectric units to meet the difference between the fluctuating load and baseload appears to be the most economical plan for serving loads in the Pacific Northwest during the next 20 years. This approach does have environmental consequences, however.

As future loads grow, the fluctuations required of the hydroelectric system will increase. These increases may exceed the allowable fluctuations. If so, other generating resources or load control procedures will be necessary. The hourly coordination of hydroelectric projects, even those that are not hydraulically coupled could, however, reduce the fluctuation in generation required of a single project. Thus, the forebay, tailwater, and outflow fluctuations required to integrate large thermal plants would be held to a minimum.

Special operations of our reservoirs for fish migration flows are mentioned in Section IV.A.1.a. Fluctuation control options are covered under "Load Effects" in Section IV.D.1.c. See the Role DEIS (A, II-75 to II-85) for additional details.

d. Summary of Coordinated Operation.

Interconnection between electric utility systems and subsequent pooled or coordinated operation yields advantages to both the utilities and their customers. Among the advantages are increases in: the possibility of being able to purchase power when needed, sometimes at lower prices than possible without coordination; the ability to sell surplus power, thereby producing revenue that otherwise would have to be obtained from the utility's customers; and assistance during emergency losses of transmission lines or generators, thereby providing more reliable service. Coordinated operations can take advantage of diversities between systems, such as diversities in loads, streamflows, and forced outages of generating units (Role DEIS: A, II-21 and IV-1).

(b) Impacts of the Thermal System.

The environmental and socioeconomic impacts of the thermal plants are presented here first for each plant individually in order to emphasize local and site-specific effects, and then aggregated in the following section to address cumulative effects on a regional level. The potential impacts of most of these thermal plants have been well documented in environmental reports and impact statements prepared specifically for each plant, and in some cases have been verified by operating data (Role DEIS: A, III-188-198).

Most of the short-term impacts of the plants are due to construction activities. Although not mentioned here in detail for each plant, these are generally localized impacts from fugitive dust, solid waste, noise, and some siltation and erosion due to runoff. Most of the operational impacts described are unavoidable adverse impacts which could occur during the life of the plant using existing technologies. Both the construction and operational activities will result in some irreversible and irretrievable commitments of resources, such as biota destroyed in the plant vicinity, construction materials that cannot be recovered, materials which are rendered radioactive but cannot be decontaminated, materials consumed or reduced to unrecoverable forms of waste, and land areas removed from present uses.

1. Individual Plants.

a. Existing Plants.

(1) Hanford Generating Plant (HGP).

Physical and biological impacts of the HGP on water, air, land, terrestrial life, and aquatic life, as well as social impacts upon the local and regional environment were evaluated in the Washington Public Power Supply System EIS (WPPSS, 1977).

Due to the discharge of the heated effluent from the once-through cooling system in the HGP, there are changes in the natural temperature regime of the river up to three to four miles from the discharge ports. This causes effects of varying magnitudes upon resident and migrating fish and other aquatic life. A 'National Pollutant Discharge Elimination System Waste Discharge Permit' No. WA-002487-2 has been issued by the State of Washington, Department of Ecology (DOE), effective March 10, 1980 to March 10, 1985. The conditions of this permit have been agreed upon by all State and Federal agencies responsible for the water quality standards and fisheries. One of the important limitations is that starting in 1983, no water above 77°F will be discharged during the period of July 1 through September 7, and prior to that time the Supply System will attempt to reschedule the annual maintenance outages of HGP to cover as much of that period as possible. Also, prior to 1983, the Supply System will notify the DOE and the Chairman of the Committee on Fisheries Operations (COFO) before March of each year as to when the outages can be scheduled. The schedules for these outages will be about the same as the schedule for the annual maintenance of the New Production Reactor (NPR), the steam supply for the HGP, owned by the U.S. Department of Energy (USDOE). It is expected that the USDOE will cooperate in scheduling NPR maintenance as close to the period as possible.

Aquatic impacts upon fish and plankton occur by impingement at the HGP intake structure and passage (entrainment) through the HGP cooling system. After modifications to the intake screens in 1976 and 1977, estimated impingement was only about 0.6 percent of the vulnerable population and survival was greater than 99 percent (WPPSS, 1977). It is judged that impingement of fish at the HGP intake affects only a few fish and does not appreciably alter fish populations.

Entrainment of plankton and other aquatic life was estimated to be negligible, that is, less than four percent of the natural river populations based upon the annual water consumption of HGP.

(2) Centralia.

The expected pollutants of sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, and particulates are emitted in quantities which meet air quality standards. The water residuals are limited to small quantities of iron and some suspended solids which increase the turbidity; these are regulated under the National Pollution Discharge Elimination System (NPDES) permit system. Heat is discharged by the cooling towers which typically results in a visible plume and a potential for local fog and icing. There is solid waste in the form of ash resulting from the plant. However, since this is a mine-mouth plant, the ash is returned to the mine (Role DEIS: A, III-189).

(3) Trojan Nuclear Plant.

The latest operational report covering environmental monitoring (Portland General Electric, 1979) indicates that no adverse environmental impacts have been noticed in the ecosystem centered around the project. All environmental variables measured in this ongoing program have fallen within the projected ranges given in the Trojan Final Environmental Impact Statement.

A small amount of the plant's waste heat discharged to the Columbia River changes the river temperature by less than 0.1°F, and has no deleterious effects on river biota or water use. Water vapor and most of the plant's waste heat is discharged to the air through the cooling tower causing a visible plume whenever the plant is operating. Thin ground fog develops occasionally but is not a hazard to transportation.

There are no deleterious effects on river biota or water use from the discharge of chemicals from the Trojan plant into the Columbia River.

No significant environmental impacts occur from normal operational releases of radioactive materials within 50 miles of the plant. The estimated dose to the population within 50 miles from operation of the plant is 3.9 man-rem/yr, less than the normal fluctuations in the 1.8×10^5 man-rem/yr background dose this population would receive, which is within prescribed Federal limits (CFR-10:50). The risk associated with accidental radiation exposure to the population is very low.

Approximately 35 acres of terrestrial habitat and flora are lost for the lifetime of the plant. An additional 200 acres have been committed to a reflecting pond and recreation areas. There is a visual impact from the presence of the plant, especially the cooling tower and transmission lines.

Minor siltation has occurred and will continue in the Columbia River adjacent to the site as a result of activities associated with construction of riverbank facilities. Minor erosion and small watercourse siltation have resulted from clearing for transmission corridors. All of these effects have occurred locally and temporarily.

There is some destruction of plankton, small fish, larvae, and fish eggs in the water intake stream. This loss is conservatively estimated to be less than 0.05 percent of the total number of biota passing the site. Maximum water consumption is approximately 0.01 percent (14,600 gpm or 32.5 cfs) of average river flow. This consumption does not constitute a permanent loss to the environment, but represents only a small change in water distribution (U.S. Atomic Energy Commission, 1973).

(4) Jim Bridger 1, 2, & 3.

The stack emissions caused by burning 750 tons of coal per hour under full operation cause no widespread adverse impacts on the salt desert shrub ecosystem, although trace elements or other fly ash constituents may affect individual plant species within one to two miles of the generating station. The emissions are within applicable Federal and Wyoming air quality standards for particulate matter and should comply for oxides of nitrogen and sulfur except in rare and uncommon situations.

Even though the emissions are generally within the standards, a localized lowering of visibility during certain weather conditions is possible.

All of the components of the project offer the potential for increased erosion with resulting lowering of surface water quality. Roughly 30,000 acre-feet of water is withdrawn from the Green River annually, but none of this water will leave the plant site to return to the Green River. The net increase in salinity of the Green River caused by withdrawal of the amount purchased is considered too minute to be measured. A minor increase in salinity (less than 2 ppm) is predicted for the Colorado River at Lake Mead.

Buried fly ash, bottom ash, and blowdown residues are not expected to contaminate ground water supplies. The geological formations involved do not lend themselves to rapid movement of water, and the arid climate further reduces the potential for percolation from the surface.

The reduction in forage and cover, when coupled with the increase in human activity caused by the complex, will have an adverse impact on wildlife. Reductions in herd sizes are not likely, but some antelope and sage grouse may leave the immediate vicinity. The impacts on rodents and other small animals driven from the disturbed area are more severe assuming their ecologic niche to be more fully occupied than is the case with big game (U.S. Department of the Interior, Bureau of Land Management, 1972).

(5) Colstrip 1 and 2.

Colstrip Units 1 and 2 discharge particulates, sulfur oxides, nitrogen oxides and other air pollutants normally associated with coal plants. The nearby mining activities discharge additional particulate and emissions associated with the operation of heavy equipment. These have deteriorated local air quality since plant construction was undertaken, but the Colstrip vicinity still meets the State and National Ambient Air Quality Standards for all pollutants except particulate. High particulate levels in Colstrip result from traffic, fugitive dust, and construction activities in the town rather than the generating units themselves. Water pollutants are not discharged to surface waters from the generating unit, but runoff from the mining areas may deteriorate surface and groundwater quality. The emissions from Colstrip of particulate, heat, and water vapor have no significant effect on climate.

Mining activities may disrupt aquifers and surface waters and have significantly altered the landscape. Both mining and the generating units have significant esthetic effects. Water for use by the generating units is withdrawn from the Yellowstone River at a maximum rate of about 21.0 cubic feet per second. Withdrawal of this water depletes flows for other potential uses and results in some entrainment and destruction of aquatic life (U.S. Department of the Interior, Geological Survey, 1979).

(6) Jim Bridger 4.

There are discharges to the atmosphere of sulfur dioxide, particulate matter and nitrogen oxides, but the proposed unit is designed to meet all applicable State of Wyoming regulations and the Federal Performance Standards for New Stationary Sources with respect to those emissions and with respect to the cumulative emissions of the four units of the total plant.

There are releases to the atmosphere of certain trace elements found in the coal. Analysis of the coal indicates there are no known health or other hazards produced by these releases, either from the individual unit or as a cumulative plant site effect (Pacific Power & Light Company, and Idaho Power Company, 1975).

(7) Boardman Coal (Carty).

There is a slight increase in the existing SO_2 ground level concentrations due to plant operations, although the resultant concentrations are well within the standards set to protect the public health and welfare. The addition of particulates has not significantly affect the air quality in the region. The resultant ground level concentration for NO_x emissions is not significant.

There will be no chemical releases to surface waters from the plant since it will operate in a zero discharge mode. Water consumption impacts will amount to 0.05 percent of the Columbia River flow. The impact of the operation of the intake structures is not expected to result in an appreciable adverse effect to aquatic life in the Columbia River.

Operation of the cooling pond will result in only gradual temperature changes which are not expected to have significant adverse effects on organisms. Heat rejection to the atmosphere will result in occasional formation of fog, although fogging and icing effects are not anticipated beyond the borders of the plant site (U.S. Department of Agriculture, 1977).

No Federal construction will be required to integrate the output of this plant into the regional transmission grid. However, Bonneville does expect to provide wheeling (transmission) services to PGE over existing BPA facilities. Although the Pacific Northwest Generating Company (PNGC) initially plans to sell its share (10 percent) of the plant's output to PGE, they are expected to withdraw this power for their own use during the mid-1980's. At that time it is possible that PNGC may request BPA or someone else to provide Fdditional services including scheduling, load shaping, and forced outage reserves.

b. Plants Under Construction.

(1) WNP-1, -2, and -4.

A small amount of the waste heat will be discharged to the Columbia River, but will change the river temperature less than 0.01°F and have no deleterious effect on river biota or water use.

Water vapor and most of the waste heat will be discharged to the air through mechanical draft cooling towers. There is a possibility of increasing fog in winter on highways a few miles from the plants for 12 to 26 hours per year in an area where natural fog occurs up to 38 days per year.

The risk associated with accidental radiation exposure is very low. No significant environmental impacts are anticipated from normal operational releases of radioactive materials. The estimated dose to the population within 50 miles due to operation of the station is 10 man-rem/yr, which is less than the normal fluctuations in the 17,100 man-rem/yr background dose this population would receive (U.S. Atomic Energy Commission, 1972; U.S. Nuclear Regulatory Commission, 1975a).

(2) WNP-3 and -5.

Heat discharged to the Chehalis River will change the river temperature less than 0.05°F 100 yards downstream of the outflow pipe.

In order to dissipate the rejected heat, a maximum of 72.5 cfs of cooling water will be withdrawn from the Chehalis River, of which 12.5 cfs will be returned to the river via pipeline with the dissolved solids concentration increased by a factor of about 6. About 60 cfs will be evaporated to the atmosphere by the cooling towers.

Chemical discharges from the plant, including chlorine, will be diluted to concentrations below that which might adversely affect aquatic biota.

The risk associated with accidental radiation exposure will be very low. No liquid radioactive releases will occur from this plant, and no significant environmental impacts are anticipated from normal operational releases of radioactive materials. The calculated dose to the estimated 1980 population which will reside within a radius of 50 miles of the plant is 11.4 man-rem/yr. This value is less than the natural fluctuations in the approximately 42,700 man-rems/yr dose this population would receive from background radiation (U.S. Nuclear Regulatory Commission, 1975b).

(3) Colstrip 3 & 4.

Colstrip Units 3 and 4 will increase emissions of particulates, sulfur oxides, nitrogen oxides, and other emissions at the Colstrip site. The Class 1 Prevention of Significant Deterioration (PSD) air quality limits have been a barrier to securing necessary permits for these units; however, Colstrip 3 and 4 will be able to comply with this requirement by using a different, more effective, air pollution control system than was originally proposed (Environment Reporter, May 4, 1979). They would also aggravate existing high particulate levels in the town of Colstrip, especially during construction, although a program is proposed to at least partially offset this increase.

Water pollutants would not be discharged to surface waters. Greater pollution of surface waters from mining area runoff will result from the accelerated mining activities. The increased emissions of particulates, heat, and water vapor will have no significant effect on climate.

Increased mining activity resulting from the addition of Units 3 and 4 would increase and accelerate the disruption of aquifers and surface waters in the mining area and increase the commitment of land area to mining. The maximum rate of water withdrawal from the Yellowstone River would be increased from 22.0 cubic feet per second to 59.0 cubic feet per second by the addition of Units 3 and 4, incurring a corresponding increase in impact on aquatic life and the availability of water for other uses.

It is not anticipated that the Northern Cheyenne or Crow Indians will realize significant economic opportunities from the Project. Low concentrations of sulfur dioxide which would result from the plants could harm some of their resources. Also, additional development of the Colstrip complex is perceived by some Indians as an encroachment on their right to self-determination (U.S. Department of the Interior, Geological Survey, 1979).

(4) Whitehorn No. 2 and 3.

The Northwest Air Pollution Authority at Mt. Vernon, Washington approved the draft EIS in September 1979 and the final EIS was issued November 6, 1979. All necessary permits have been issued or approved except the FUA permit discussed in the project description. Environmental impacts are evaluated in Puget Sound Power & Light Company's EIS. Ref: Final Environmental Impact

Statement, Proposed Addition of Combustion Turbine Units 2 and 3 of Whitehorn Generating Station, issued by Northwest Air Pollution Authority, Mt. Vernon, Washington, November 6, 1979.

c. Committed Plants.

(1) Columbia 1 and 2.

These units are 1288 MWe General Electric boiling water reactors with Mark III containment. Method of cooling in the Skagit location was to be accomplished by natural draft cooling towers, but this design may change. The turbine generator is a Westinghouse 1340 MW unit. Ownership of the project at present is Puget Sound Power & Light 40 percent, Pacific Power & Light 20 percent, Portland General Electric 30 percent, and Washington Water Power 10 percent.

Environmental, geological, and engineering designs are being reassessed relative to the new proposed location at Handford, Washington. It is presently planned that applicable Federal and State siting documents will be filed by December 1981.

(2) Pebble Springs 1 & 2.

For these plants, a closed cycle system using a cooling pond is to be used to transfer the heat from the plants to the atmosphere. Makeup water will be drawn from the Columbia River but there will be no return to the river, thus no temperature increase. Because of the cooling pond arrangement there will be no releases to the river. The plants will incorporate as much zero release technology as possible in order to maintain the quality of the reservoir.

The risk associated with accidental radiation exposure will be very low. There will be an annual dose of 9.5 man-rem/yr to the population within 50 miles resulting from the operation of the station. This dose will be less than the normal fluctuations in the 8,070 man-rem/yr natural background dose this population now receives (U.S. Nuclear Regulatory Commission, 1975d).

d. Proposed Plants.

The listed proposed plants, Creston and Kettle Falls, are still in the investigation stage and have no site specific applications or environmental documents as of this writing. The owners will be required to meet all applicable regulations and secure all required permits. As of this time, only generic environmental impact values are applicable. Refer to IV.B.2. for a discussion of these impacts.

2. Cumulative Regional Impacts.

Section IV.A.1.a(2)(b) addresses individual impacts of the principal existing and committed thermal powerplants which serve or are planned to serve West Group loads. Some types of impacts, such as noise, land use, physical impacts of construction, and solid waste, are site specific, so that it is not possible to assess these types of impacts on a regionwide basis. Water consumption and discharges of pollutants are probably best evaluated on the basis of river basins rather than regionally.

a. Air.

Air quality and radiological impacts of all these projects can be addressed on a regionwide basis. Two studies quantifying the regionwide impacts of thermal plants are reviewed here.

(1) Environmental Impacts of the Generation of Electricity in the Pacific Northwest.

(Equitable Environmental Health, Inc., 1976) This study attempted to determine the regional and subregional environmental impacts within the BPA service region of several possible future scenarios of thermal plant development. One case, Scenario B, assumed that all the existing and committed plants listed in Table IV-3, plus two other 500 MW coal plants and a 1,250 MW nuclear plant, would become operational. This case approximates the impacts of the "existing" system upon which the impacts in this section are based, but because of the three additional plants, impacts are slightly higher than actually expected. Equitable's results for this case, with the three "extra" plants distributed randomly over the portion of the BPA service region where siting would be feasible, are tabulated in Table IV-4 (Role DEIS: 1, V 309).

The Equitable report addressed impacts which occurred only within the BPA service area (i.e. Washington, Oregon, Idaho, and Western Montana). Therefore, its results include all the region's existing and committed nuclear plants, but neglects the impacts of those existing and committed coal-fired generating units which meet regional needs, yet are located outside the region.

TABLE IV-4

REGIONWIDE IMPACTS OF A 50-50 MIXTURE OF COAL AND NUCLEAR THERMAL PLANTS AS PREDICTED BY EQUITABLE ENVIRONMENTAL HEALTH, INC. 1975-1995

Source of Impact	Type of Impact	Amount of Impact
Air Pollutants		
Radioactive Emissions	Human Deaths	1×10^{-5} deaths/20 yr. period
	Human Defects	1×10^{-5} deaths/20 yr. period
Nonradioactive Emissions	Human Health	Aggravation of symptoms in persons having respiratory disease and those predisposed to such disease
	Damage to Flora	Plants which are particularly sensitive to powerplant pollutants may be damaged
	Damage to Materials	Negligible
	Weather Modification	Negligible
	Esthetics	Frequent intrusions of visible cooling tower plumes and occasional reductions in visibility
Water Pollutants		
Radioactive	Human Deaths	1×10^{-6} deaths/20 yr. period
	Human Defects	1×10^{-6} deaths/20 yr. period
Nonradioactive	Human Health	Not medically detectable
	Damage to Flora and	Elimination of some Faun species from and reduction of species diversity in the mixing zone within the receiving waters
Solid Waste		
Radioactive	Human Deaths	1×10^{-3} deaths/20 yr. period
	Human Defects	8×10^{-4} deaths/20 yr. period
Population Land Disturbance	Disruption and Demand for Services	Small
	Esthetic Instrusion	Small

(2) Regional Air Quality Assessment for Probable Near-Term Coal-Related Energy Development in the Pacific Northwest.

(Renne, D. S. and Elliott, D. L., 1976.) This study addressed air quality impacts of probable coal developments in Washington, Oregon, Idaho, Montana, and Wyoming. These plants include all the coal-fired resources being considered for this EIS plus some additional plants. Overall impacts predicted by this study are greater than what would result from the coal-fired resources being considered for this EIS because of the inclusion of the Eden Ridge and Pioneer plants which are no longer planned for construction and a number of other coal powerplants and proposed coal gasification plants in Wyoming. The following excerpt from this study sets forth its major conclusions:

> With respect to the National Ambient Air Quality Standards (NAAQS), no significant incremental amounts of SO_2, particulates, or NO_x are added to the background level of regional air concentrations beyond the immediate vicinity of the plant. National standards have not been established for sulfates, although the State of Montana has established its own standards. Here, the modeling shows that the amounts added by new coal-fired power plants, in additional to all existing sulfur emitters, may approach the limit set for maximum allowable sulfate concentrations if emissions are as high as the New Source Performance Standards (NSPS). NSPS limits SO_2 emissions to less than 1.2 lb/10^6 Btu fired. 1/ In actual practice, emissions may be considerably less, due either to the combustion of low sulfur coal or the application of control technology. This result has important implications on the siting of future additional plants in this State.
>
> There were generally higher air concentrations of all pollutants in July and October, mainly due to lower mean wind speeds. Air concentrations are generally lower in April and December because of greater mean wind speeds and precipitation scavenging.
>
> Topography influences the concentration patterns of all pollutants. Mostly, these patterns reflect the wind flow characteristics in the vicinity of the source but are modified by wet and dry removal processes.
>
> Sulfate concentrations and depositions decrease much more slowly with distance from the source than SO_2 concentrations and depositions, primarily due to the time lag involved in the chemical transformation and to differences in the removal mechanisms. Beyond distances of 50 to 100 km, sulfate concentrations generally exceed SO_2 concentrations.

1/ Since this study was performed, revisions to these standards have been made which will impose more stringent requirements on future coal-fired powerplants.

Concentration patterns of NO_x resemble those of SO_2, whereas concentration patterns of particulates resemble those of sulfate. Removal rates for NO_x are assumed to be similar to those of SO_2, while the removal rates for particulates are assumed to be similar to those of sulfates.

For sulfur sources located in basins bordered or surrounded by mountainous terrain (e.g., Puget Sound, Columbia Basin, Snake River Valley 2/), a major portion of the sulfur emissions are deposited onto the terrestrial environment as SO_2 and sulfates. Over the Great Plains of Montana and Wyoming, there is considerably less deposition and a larger portion of the SO_2 emitted remains in the air as sulfate to be transported out of the region.

The fraction of SO_2 deposited is substantially different between the July and December periods, primarily as a result of the seasonal variations in precipitation. In dry regions, approximately 45 to 60 percent of the SO_2 emitted is deposited as SO_2 (depending on the surrounding terrain), while in wet regions 75 percent or more may be deposited.

As much as 1 g/m^2-yr or more, which is approximately 10 lb/-acre-yr, of sulfur (in the form of both SO_2 and sulfates), can be deposited onto the terrestrial environment in the vicinity of a large power plant.

The most significant increases in ambient air concentrations and surface deposition resulting from the possible near-term development scenario will be in the northern Great Plains, the Snake River Valley 2/, and in eastern Washington and Oregon.

Concentrations of air pollutants caused by coal-fired plants will aggravate symptoms in persons having respiratory disease and may cause greater occurrence of respiratory disease in predisposed individuals, particularly in the areas having the highest average pollutant concentrations as shown on the figures. Flora and fauna which are particularly sensitive to air pollutants from coal-fired plants may suffer damage in these same areas. Aerial transport of sulfate out of the region may exacerbate existing problems with acid rain and sulfate deposition elsewhere.

2/ Projected impacts in the Snake River Valley resulted from inclusion of the Pioneer plant, a plant which is no longer planned. These impacts are, therefore, no longer predicted.

b. Water.

Only the Columbia and Chehalis Rivers are affected by multiple plant sites; the other projects involve multiple units at one site affecting individual streams. The cumulative impacts in the latter cases can be readily extrapolated from the earlier brief discussions of plant impacts and from the site-specific environmental statements and reports. Cumulative effects of the thermal plants on the Columbia and Chehalis river systems are relatively minor. The withdrawal of water from the rivers results in some destruction of aquatic life through entrainment and impingement on the pumping structures. Withdrawal of water also decreases the amount available for other uses such as irrigation and hydroelectric generation, but these losses are not significant with respect to total river flows.

c. Nuclear Waste and Plant Decommissioning.

(1) Nuclear Waste Management.

Spent nuclear fuel must be disposed of, with or without reprocessing, after it is taken from the reactor. Reprocessing involves chemical removal of the remaining plutonium and uranium, leaving a residue of radioactive isotope byproducts (Role DEIS: 1, V-247). These byproducts currently are considered as waste, as there are no economic uses that require large amounts of the isotopes. Given the highly radioactive nature of this material, it cannot be disposed of by conventional means.

Several disposal methods have been proposed, which DOE has categorized as "commercialized" or "available." The reader is referred to Draft Environmental Impact Statement, Management of Commercially Generated Radioactive Wastes (U.S. DOE, 1979) for a detailed description of these options and their status. Burying the waste deep underground in a stable geologic formation appears to be the most promising solution in the long term.

In 1977, President Carter indicated in his nuclear power policy statement that this country will defer indefinitely the commercial reprocessing and recycling of the plutonium produced in the United States nuclear power programs. Under the Administration plan, the government will take title to the spent fuel, with the utilities paying for transport of the fuel to a government-approved storage site. Utilities will also pay a one-time fee to cover the costs of interim storage and ultimate disposal in a permanent repository. Although estimates for this one-time fee run as high as $200/kg, a fee somewhere between $100 and $200 is considered most likely. (Washington Public Power Supply System, 1978, p. 66) The amount necessary to pay this fee is collected by the utility at the time the fuel is used and is included in the fuel costs.

Present plans call for Northwest reactors to store their spent fuel onsite until a storage or terminal waste disposal technology is implemented. Pacific Northwest reactors still in the design or construction stage also have been modified to increase spent-fuel storage capability. There would be neglible impacts from long-term low-level radiation (U.S. Nuclear Regulatory Commission, 1977).

(2) Decommissioning of Nuclear Plants.

Today's nuclear powerplants are designed and financed for a 30 to 40 year lifetime. It is expected that at the end of this period, the plant will be obsolete and uneconomic. If this is not the case, the plant may be overhauled and continued in service. When the plant no longer meets its owner's requirements, it will be shut down and decommissioned (Role DEIS: 1, V-97-99).

Most of the buildings and structures of a nuclear powerplant--cooling tower, control room, and switchyard--present no special hazards and can be torn down and removed much like any industrial structure of the same type. The parts of the powerplant outside of the reactor containment that deal with radioactivity are relatively easily decontaminated or dismantled and present only a slight additional cost.

The containment building represents a small portion of a typical 700-acre site. There are procedures for repairing and replacing most all equipment housed in the containment, except the reactor vessel, during normal plant maintenance periods or after the reactor is shut down And defueled. Some equipment would probably be sold, such as the overhead crane and pump motor, and some retained for further operation during decommissioning.

A decommissioning plan begins with defueling the reactor and removing all fuel offsite. This would be carried out using normal plant procedures. At this point, work could proceed within the containment in order to remove any equipment and to seal the containment. It would be most economical at this time to allow the sealed containment to sit for a period of about 10 years, so that most of the short-lived radioisotopes would decay to insignificant levels.

There are two ways in which decommissioning can be accomplished, either by entombment or by dismantling the reactor. In order to allow for minimum manning of the site and no maintenance, the reactor could be entombed inside the biological shield, with a combination of concrete epoxy and asphalt. All removable equipment would be shipped offsite. Then the containment building would be brought down, and the biological shield mounded over with clean rubble and fill. The area would probably then be seeded and surrounded by a fence. This structure would have to withstand natural forces for about 200 years with no maintenance. Site monitoring would be required.

If the site is to be completely abandoned or restored to its original contours, the reactor vessel itself must be removed. Most items in direct contact with the neutron flux of the reactor will have become activated and present a radiological hazard if they are removed from their shielding. This would include the reactor pressure vessel, all internal reactor parts, and short lengths of pipe leading to or from the reactor. The smaller parts could be sealed into shielded containers underwater and shipped offsite for burial in a Federal repository. The larger pieces and the reactor pressure vessel would then be cut underwater by remote control and sealed into shielded containers for economical shipment to the burial site. Once the 10-year cooling period has lapsed and the reactor removed, the remaining structure can be razed in a normal manner. This is the most expensive option available today, but once complete, it requires no further expenditure by the owners.

The costs of any of these options are not expected to be excessive. In 1978, the most recent study by the NRC estimated costs for decommissioning a large power reactor of the pressurized water type (a boiling water reactor presents no additional problems) at less than 10 percent of the cost of construction (Smith, Konzek, Kennedy, et al., 1978). Depending on the method of decommissioning employed, costs may range up to 15 percent of construction costs.

(3) Investment Costs.

System costs associated with the construction and operation of the region's thermal and hydro generating resources are summarized on Tables IV-5 and IV-6, respectively. Thermal plant capital and annual operating costs are presented for those existing, under construction, or committed projects, pursuant to the Hydro-Thermal Power Program. FCRPS investment costs are presented for the period 1965 through 1985.

TABLE IV-5

CONSTRUCTION AND OPERATING COSTS ASSOCIATED WITH THERMAL POWER PLANTS
(As of August 1980)

Plant	Total Construction Costs	Annual Operating Costs	Bus Bar Energy Costs
	(Millions of dollars)		(Mills/kWh)
In Operation 1/			
Hanford (HGP) 7/	2/	22	10
Centralia 1&2 7/	316	129	14
Jim Bridger 1,2&3	365	N/A	N/A
Colstrip 1&2	260	N/A	N/A
Trojan 7/	480	30 3/	15
Jim Bridger 4	348 5/	N/A	N/A
Boardman (Carty)	519 5/	N/A	N/A
Under Construction			
WNP-1 6/	2,736	393	51
WNP-2 6/	2,467	376	56
WNP-3 6/	3,130 4/	300	56
WNP-4 6/	3,614	504	66
WNP-5 6/	4,001 4/	450	66
Committed			
Colstrip 3&4	1,071 5/	N/A	N/A
Columbia 1&2	2,929 5/	N/A	N/A
Pebble Springs 1&2	2,668 5/	N/A	N/A
Total	24,904		

1/ Capital costs are as of commercial operation dates for resources in operation.

2/ Capital costs for the Hanford project are not shown because the project includes only the steam delivery and turbine-generator systems, since it was built to utilize waste heat from an existing reactor.

3/ Annual cost includes only the portion owned by the Eugene Water and Electric Board. Cost for privately-owned portions would probable be higher.

4/ These costs are for the publicly-owned portions only (70 percent of WNP-3 and 90 percent of WNP-5). Information on the costs to private utilities is not available; therefore, without total costs, interest during construction and financing costs are not included.

5/ Estimated--January 1978.

6/ Total Construction Costs are based on the Supply System's 1981 construction budgets. Annual Operating Costs and Bus Bar Energy Costs are 1990 costs at 70 percent capacity factor.

7/ Annual Operating Costs and Bus Bar Energy Costs are based on annual operating budgets.

N/A Not Available

TABLE IV-6

FCRPS
SCHEDULE OF PLANT INVESTMENT - 1965-1985
(Thousands of dollars)

Fiscal Year	Construction Work in Progress	Total Commercial Power	Total Completed Plant
1965	318,044 1/	1,458,889	1,776,933 1/
1970	673,420 1/	2,075,592	2,749,012 1/
1975	1,079,220 1/	2,811,143	3,890,363 1/
1978 (Sept. 30)	771,665	6,159,895	5,388,230
1980	758,028 3/	5,511,359	6,269,387 2/
1985	758,028 3/	7,190,101	7,948,129 2/

1/ From Summary of Financial Data (Balance Sheets)
2/ From 1978 Repayment (5-Deck)
3/ Levelized from 1978 Balance Sheet

b. Conservation.

(1) Programs.

Existing regional conservation programs and programs which are being developed independently of BPA's proposal or alternatives are discussed in this section. Both public and private institutions are involved in these programs.

(a) Federal Programs.

The major Federal programs to impact electricity consumption resulted from the passage of the National Energy Act (NEA) during 1978. Although largely concerned with the conservation and production of oil and natural gas, certain titles and sections of three of the five bills in the NEA are of particular interest to electricity producers and consumers. These three bills are the National Energy Conservation Policy Act (NECPA), the Public Utilities Regulatory Policies Act (PURPA), and the Energy Tax Act. The important elements of these bills are summarized below:

1) National Energy Conservation Policy Act (NECPA) Title II - Residential Energy Conservation.

Part 1: Utility Conservation Program for Residences. This program requires utilities to offer energy audits to their residential customers that would identify appropriate energy conservation and solar energy measures and estimate their likely costs and savings. Utilities also are required to offer to arrange for the installation and financing of such measures.

Part 1 applies to electric utilities with annual sales in the second preceding calendar year of 750 million kWh or more. This threshold level of energy sales was exceeded during 1977 by all 7 major investor-owned utilities in the region and by 11 publicly owned utilities - a municipal system and a PUD in Oregon, and 2 municipal systems and 7 PUDs in Washington.

In 1977, these utilities' residential customers represented approximately 62 percent of residential customers served by BPA preference customers, and 85 percent of all residential customers in the region.

Assuming no significant change in the NEA provisions or in the portion of total regional residential sales and customers served by these utilities, by 1990, 35 covered utilities, including those owned by stockholders, would be serving over 75 percent of BPA preference customers' residential customers and approximately 90 percent of all residential customers in the region. Similar portions of residential energy sales would also be covered by NECPA.

Part 2: Weatherization Grants for Low-Income Families. This part of NECPA extends the DOE weatherization grants program for insulating lower-income homes through 1980 at an authorized level of $200 million in fiscal years 1979 and 1980.

Part 3: Energy Conservation and Solar Energy Loan Programs. This part provides $100 million administered by HUD which will provide support for loans of up to $8,000 to homeowners and builders for the purchase and installation of solar heating and cooling equipment in residential units. It also provides $5 billion for Federally supported home improvement loans for energy conservation measures, $3 billion for support of reduced-interest loans up to $2,500 for elderly or moderate-income families, $2 billion for general standby financing assistance, and provides improvements in multi-family housing.

Part 4 provides grants and establishes standards for energy conservation in Federally-assisted housing.

Title III - Conservation Programs for Schools, Hospitals, and Local Government Buildings.

Part 1: Grant Program for Schools and Hospitals. This program provides grants of $900 million over the next 3 years to improve the energy efficiency of schools and hospitals.

Part 2: Energy Audits for Public Buildings. This part establishes a 2-year, $65 million program for energy audits in local public buildings and public care institutions.

Title IV - Energy Efficiency of Products and Processes

Part 2: Appliance Efficiency Standards. This part requires that energy efficiency standards be established for major home appliances, such as refrigerators and air-conditioning units.

Part 3 requires energy efficiency labelling of industrial equipment.

Part 4 sets industrial recycling targets and reporting requirements.

Other Provisions. Title V of NECPA provides $100 million for a solar demonstration program in Federal buildings (Part 2), sets conservation requirements for Federal buildings (Part 3), and provides $98 million for solar photovoltaic systems in Federal facilities (Part 4).

2) Energy Tax Act of 1978.

This Act provides tax incentives for investments in conservation measures and alternate end-use resources. These incentives include tax credits for residential weatherization, for solar or wind equipment, and for geothermal energy.

(b) State Programs.

State governments in the region have developed extensive energy conservation programs as a result of the recognition of the need for such programs, and because of Federal pressure on states to develop these programs. Each state has created a state energy office to develop and administer conservation programs.

As a result of the Federal Energy Policy and Conservation Act of 1975, each state in the region has prepared an Energy Plan which demonstrates how it plans to save at least 5 percent of the total energy (including both electricity and other forms of energy) it might otherwise have required in 1980. Although the plans do not address energy conservation beyond 1980, they would presumably continue to save energy beyond this date. Table IV-7 summarizes the components of plans for Pacific Northwest states.

(c) Utility Programs.

Utilities in Oregon and Washington have extensive conservation programs. In Oregon, because of state law, utilities must provide conservation information to their customers and, depending on the type of utility, either provide information on or arrange for financing and installation of insulation for their space heating customers. Some Oregon utilities have gone beyond these requirements. Pacific Power & Light (PP&L), Portland General Electric (PGE), and CP National (formerly California-Pacific Utilities) offer no-interest weatherization loans, support weatherization and solar research, and perform commercial and industrial energy audits. Eugene Water & Electric Board (EWEB) has an Energy Efficient Home Award program and is helping develop cogeneration and municipal waste generation. EWEB also has conducted research on electric vehicles and super-insulated homes. Other publicly-owned utilities in Oregon are participating in a regional Energy Efficient Home Award program.

Three investor-owned utilities in Washington offer no-interest loans for weatherization for residential customers, similar to private utility programs in Oregon. Clark County PUD has an energy-efficient home program more stringent than the state code, and also performs residential energy audits and conservation seminars. Seattle City Light promotes conservation in its service area with a variety of nonfinancial incentives.

Utilities in Montana and Idaho have encouraged conservation primarily with information programs.

TABLE IV-7

SUMMARY OF STATE ENERGY CONSERVATION PLANS

PROGRAM	STATE			
	ID	MT	OR	WA
Residential				
Alternate Energy Tax Incentives	X	X	X	X
Electronic Ignition Devices on Gas Appliances			X	
FmHA Weatherization Loans			X	
Home Energy Audits	X	X	X	X
HUD Block Grants			X	
Individual Metering, Multi-Family Residences			X	
Low-Income/Elderly Weatherization	X	X	X	
Private Utility Weatherization/Conservation Services Program		X	X	
Public Utility--Oil Heat Dealers Weatherization/ Conservation Services Program			X	
Residential Thermal Insulation Standards	X	X	X	X
Veteran's Weatherization Program			X	
Voluntary Energy Efficiency Rating for Single-Family Homes			X	
Weatherization Tax Incentives	X	X	X	
Industrial/Commercial				
Cogeneration		X	X	
Commercial Building Thermal Standards		X		
Energy Audits	X	X	X	
Industrial Energy Research			X	
Public Utility Measures Program (Rate Structures, Industrial Cogeneration)		X		
Recycling Information/Bottle Bill			X	
Refuse Generation	X			
Waste Wood Recovery/Biomass	X			X
Workshops/Seminars	X		X	
Government				
Convert State-Owned Heating Plants to Renewable Fuels			X	
Energy Management, Maintenance, Inventory, and Audit Programs for State Buildings	X	X		X
Government Procurement Practices	X	X		
Public Building Lighting Standards	X	X	X	X
Voluntary Retrofit Lighting Standards for Public Buildings		X		

(d) BPA Programs.

BPA's Energy Conservation Office was first staffed in 1973. BPA has held information and education programs for its employees and reduced its own internal annual energy consumption by over 24 percent between 1973 and 1978.

BPA's external conservation efforts have been primarily limited to information and education programs for the region's utilities and electricity consumers. A notable exception is the coordination and cosponsoring of aerial infrared thermography projects with its utility customers to help them point out possible heat losses from their customers' buildings.

(e) Other Programs.

These programs include city and county building codes and local low-income weatherization grants and loan programs utilizing CETA employee manpower.

(2) Program Impacts.

The present status of conservation in the region is characterized by inconsistent and uncoordinated approaches which lead to ineffective regional planning and progress toward actually investing in conservation. These approaches vary widely from state to state and even among utilities within a particular state. In some cases, strong incentive programs as well as technical assistance are being provided. In others, little more than public information programs are available. Many programs are aimed at conservation of residential energy, which accounts for about one-fifth of total electrical use; but when commercial, industrial, and agricultural sectors are considered, programs are few in number and effective ones are practically nonexistent.

There is a lack of adequate mechanisms for actually "investing" in energy conservation as an energy resource. Perhaps the greatest difficulty in overcoming this lack is finding ways to view conservation in the context of marginal-cost economics. Electricity consumers evaluate the cost-effectiveness of conservation using prices they pay for electricity and thus receive an improper signal as to the economic amount of conservation in which to invest. Government and utility conservation programs attempt to overcome this problem by raising prices consumers pay for all or part of their electricity. The wide variety of conservation programs and gaps in program coverage, however, are indications that government and utilities are having problems using marginal-cost evaluation of conservation programs.

Little progress is being made towards encouraging direct use of renewable resources as a conservation measure to displace the use of electricity. While the Pacific Northwest has considerable potential indigenous energy resources--wood, geothermal, wind, and solar energy--most government programs have done little towards encouraging the efficient use of these resources to displace electricity. People are using more of these resources on their own, and in Oregon a state solar energy tax credit incentive program is helping. However, in general, government and utilities have not encouraged the use of these resources in the Pacific Northwest.

The contribution potentially available from conservation has continued to be a disputed matter in utility planning. Part of the problem relates to how much conservation may occur "naturally" as a result of rising energy prices versus how much can be "planned". Moreover, the short leadtime for many conservation measures in comparison to the long leadtime for powerplants makes it difficult to compare them.

While it is difficult to estimate how much impact present programs have made, there has been a reduction in electricity energy consumption over what might otherwise have occurred. In the 5 years prior to 1973, which marks the inauguration of many conservation efforts, the compound annual rate of growth for the total West Group Area energy loads was 5.6 percent. In the 5 years following 1973, the compound annual rate of growth dropped dramatically to about 3.3 percent. Some, but by no means all, of this decreases in growth rates of population or economic activity, warmer than normal weather, and higher prices. Many persons directly involved in energy planning, however, believe that a significant portion of the reduction is due to conservation programs.

A further reflection of the impact of conservation programs may be evident in load forecasts. For example, the PNUCC's 1975 forecast of West Group Area loads predicted a compound annual rate of growth of about 4.8 percent for the first 10 years of that estimate. The 1977 forecast of loads dropped to 4.2 percent for the first 10 years of the forecast, and the 1979 forecast indicated a 3.9 percent annual growth rate. In addition, forecasts prepared by the State energy agencies and by some other interested groups indicate even lower growth rates. Conservation programs are partially responsible for the lower load growth forecasts (Role DEIS: C, IV-250).

Environmental impacts of conservation are discussed on p. IV-117 below.

2. Marketing.

a. Customer Services.

BPA utilizes the FCRPS to provide a variety of services to customers requesting them, including load factoring, forced outage and load growth reserves, wheeling, trust agency power purchases, and surplus sales. BPA's goal in providing such services is to make maximum use of Federal facilities and resources as well as other regional resources. BPA's provision of these services does not prohibit customers from operating independently.

(1) Load Factoring.

Load factoring service is the function by which the output of generating projects is shaped for delivery at such times and in such amounts as is usable in a utility's load. The amount of load factoring service is limited by available hydro capacity, which is influenced by limitations on river and reservoir fluctuations, and BPA's ability to store off-peak energy, which is affected by the minimum level of river flows and the amount of off-peak load. BPA would first provide load factoring service for Federal system generating projects as required by the delivery provisions of power sales contracts with its customers, and secondly, with remaining capacity and storage for utilities' generating projects.

(2) Load Growth Reserves.

As discussed in Chapter III, load growth reserves (LGR) are generating capacity set aside to meet unanticipated load growth in a given year. BPA currently maintains LGR in an amount of power approximately equal to one-half of the region's annual utility load growth. This amount is adjusted periodically to reflect more accurate forecasts and changing power availability.

Reserve power not utilized by the utilities is marketed in the region as surplus energy, as well as in the form of increased availablity of the top two quartiles of industrial firm power. These markets serve to increase BPA revenues.

Currently, BPA is obligated to provide the load growth reserves for all its public agency customers and two investor-owned utilities (PP&L and PGE) in the Pacific Northwest. Until 1983, BPA will continue to meet the load growth requirements of its preference customers. Then in the absence of new action which would allow BPA to meet the post 1983 growth, each customer will be responsible for its own load growth. This is the result of projected loads being greater than the capacity and energy capabilities of the FCRPS under critical or near-critical water conditions.

The other Northwest private utilities currently provide for LGR with interutility purchases inside and outside the region, secondary power purchases from the FCRPS, and safety margins in construction schedules. Any surplus power is sold to other utilities, industry, and over the Pacific Northwest-Pacific Southwest Intertie.

Delays in thermal plant construction in the region have jeopardized future load growth reserves, as well as firm power resources. Due to these delays, the probability of the DSI loads being interrupted will increase and the region's combustion turbines could be utilized more often, and even with these measures, in low water years, shortages may require voluntary or mandatory load reductions in all sectors. As one means of reducing load growth, utilities are developing conservation programs to reduce waste and make more efficient use of available resources.

(3) Forced Outage Reserves (FOR).

Each generating utility in the region currently provides for forced outage reserves through its own resources and participation in the Northwest Power Pool (NWPP). Reserves are provided through additional equipment and stored water in the case of hydro resources, and in plant capacity factors for thermal. The reserve pool provides backup reserves for an individual utility in the event that its resources are not adequate to meet emergency conditions.

BPA technically provides forced outage reserves to the generating public utilities which are not members of the NWPP or not party to the Coordination Agreement, due to contract requirements for meeting total demand. For others, this service is provided through the NWPP. Nongenerating utilities have no need for forced outage reserves. Private utilities currently have access to this service through mutual backup provided by the Coordination Agreement.

Regional pooling of reserves allows for more efficient use of the region's resources by spreading the risks of forced outages throughout the system. Thus, less idle capacity must be held in reserve, which reduces the amount of resources required.

(4) Trust Agency Power Purchases and Surplus Sales.

BPA currently arranges for utility and industry power purchases from outside sources upon request. To date, the use of this service has been primarily limited to BPA serving as a single point through which purchases/sales can be channelled for the DSIs. This provides a mechanism to balance individual customers' surpluses and deficits.

BPA has Industrial Replacement Energy (IRE) agreements with 15 industrial customers. These IRE agreements provide for BPA to endeavor to arrange for the purchase of generation for delivery to the industries during power restrictions by BPA. BPA is generally notified by utilities when blocks of energy become surplus to their needs, but also canvasses NW utilities regarding the availability of such energy. BPA occasionally arranges to use such energy to serve its own loads but most often coordinates the amount of energy, price, and terms of delivery with the DSI consultant for dissemination among and purchase by the DSIs. Provisions are made to shape this energy into the DSI loads, including both storage and advance delivery services. However, all schedules of energy delivery and other services are provided such that there is no adverse impact on the operation of the Coordinated System reservoirs. BPA does benefit from head gains when energy is stored and the right to pre-empt such energy when needed to serve firm loads. As expected shortages increase to include the preference customers, arrangements similar to the IRE agreements probably also will be requested. At present, the preference customers are being either served totally by BPA or have their own staff and facilities to purchase power and shape their load.

b. Allocations.

(1) Customer Profile.

BPA's 147 customers can be grouped into four major classes: public agencies (including municipalities and PUDs) and cooperatives, investor-owned utilities, direct-service industries (including aluminum companies and other industries), and government agencies.

In accordance with the "Preference Clause" provisions of the Bonneville Project Act, BPA gives priority for Federal power to public agencies and cooperatives within the region. Most of these preference customers are either totally dependent on BPA for power or own their own generation and purchase supplemental power from BPA. As revealed in Table 1V-8, they are BPA's largest customer bloc, both in number (116) and in quantity of energy purchased (44 percent of fiscal year 1978 total BPA sales).

Direct-service industrial (DSI) customers constitute the second largest bloc. Among them, the aluminum industry is the largest consumer, accounting for nearly one-third of BPA's total fiscal year 1978 energy sales.

The third bloc comprises investor-owned utilities which purchased 12.8 percent of BPA fiscal year 1978 energy sales. These companies either totally own or jointly own additional power generation outside of BPA.

Government agencies constitute BPA's smallest customer bloc. Those Northwest agencies serviced by BPA are treated as preference customers.

In addition to the above customers, BPA sells power outside the region when it is surplus to Northwest needs and cannot be conserved for later use. In fiscal year 1978, this surplus power accounted for 8.2 percent of BPA's total sales.

BPA's policy in distributing Federal System power among its customers has been to allocate:

-- firm capacity and energy and nonfirm energy first to preference customers and Federal agencies in the Pacific Northwest region,

-- remaining firm and nonfirm capacity and energy to direct-service industrial customers (DSIs) and Northwest investor-owned utilities,

-- nonfirm capacity and energy first to preference customers and then to investor-owned utilities outside the region.

(2) Types of Power.

In marketing the energy from the FCRPS system, BPA cannot assure delivery of any more power than is continuously available in minimal, or critical water years (see Section IV.A.1). This power, on which delivery can be assured even under worst case circumstances, is called firm power. The firm power which BPA delivers is either obligated in "requirements" contracts, stated contract amounts, or computed amounts which are determined by BPA's customer loads and resources. In fiscal year 1978, the firm power sales accounted for 74.3 percent of BPA's total energy sales (see Table IV-8).

Table IV-8
SUMMARY OF BPA'S ELECTRIC ENERGY SALES BY CLASS OF CUSTOMER
(Fiscal Year 1978)

Customer Class	Total Number of Customers	Electric Energy Sales in KWH (000) FIRM	NONFIRM Secondary	NONFIRM Industrial	NONFIRM Surplus	TOTAL	Percent of Total Sales
Northwest Area	147	56,855,022	8,865,848	4,543,979	-	70,264,849	91.8
Preference Customers	116	33,427,843	249,818	-	-	33,667,660	44.0
Municipalities	36	9,134,467	183,691	-	-	9,318,158	12.2
Public Utility Districts	26	17,803,346	63,275	-	-	17,866,621	23.3
Cooperatives	54	6,490,030	2,852	-	-	6,492,882	8.5
Federal & State Agenc.	6	745,704	-	-	-	745,704	1.0
Privately Owned Utilities	8	1,192,312	8,616,030	-	-	9,808,342	12.8
Aluminum Companies	6	19,721,037	-	4,221,138	-	23,942,175	31.3
Other Industries	11	1,768,126	-	322,841	-	2,090,967	2.7
Outside Northwest Area	13	-	-	-	6,246,237	6,246,237	8.2
Publicly Owned	6	-	-	-	1,269,312	1,269,312	1.7
Privately Owned	3	-	-	-	3,757,270	3,757,270	4.9
Federal & State Agenc.	4	-	-	-	1,219,655	1,219,655	1.6
TOTAL	160	56,855,022	8,865,848	4,543,979	6,246,237	76,511,086	100.0

In most years, the FCRPS has more water from rain and snowmelt than the critical level. Accordingly, more electrical energy can be generated in most years than in a critical water year. This additional generation is sold by BPA as nonfirm power. This nonfirm power is all power in excess of the firm power which BPA is obligated to deliver to its customers. The two principal kinds of nonfirm power are secondary power and surplus power. Secondary power is nonfirm power delivered to public agencies, DSIs, and investor-owned utilities in the Pacific Northwest. Surplus power is nonfirm power delivered to utilities and others outside the Pacific Northwest. Secondary power sold to industrial customers includes the 25 percent of all contract demand of industrial firm power which BPA can restrict at any time (sometimes called interruptible power) and nonfirm energy sold to industrial customers (called authorized increase). Firm, interruptible, and nonfirm power indicate the quality of the power provided in reference to conditions of availability. BPA sells this energy according to wholesale rate schedules which consist of seven different rate classifications. Those schedules are summarized in the Rates section of this chapter.

(3) Impacts of BPA's Current Allocation Policies.

A wide discrepancy exists in the saturation of public power from state to state. In the BPA service area, most public utilities are located in the State of Washington, with relatively few in Oregon, Idaho, and Montana. The geographic distribution of BPA power sales reflects this situation. The State of Washington has nearly 50 percent of the region's preference customers, and accounted for over 72 percent of BPA's total energy sales to this customer class. As public customer loads have increased, less BPA power has been available for private utilities and they have had to turn to more expensive thermal generation to replace the Federal power which they previously received. The impact of this has been a widening disparity of electric energy prices in the region. Although, as indicated in the section on Rates below, many factors contribute to this rate disparity, the access to BPA power accorded preference customers has been one of the most significant factors. Additionally, because there is currently no firm power available for contracting, there is no incentive at this point for the formation of new public bodies and cooperatives. This situation may change in the early 1980's when the customer contracts and contracts with the DSIs and existing preference customers begin to expire. Under present circumstances, BPA will not be able to renew the industrial contracts. (For a more complete discussion of the impacts of DSI allocations, please see Section e of this chapter.)

BPA's current contracts with preference customers provide that the allocation for each in 1983 will be based on its load, but the load may not exceed 103 percent of estimates dated December 1973. If load growth exceeds this amount, for whatever reasons, the customers will require more resources from others after 1983 when BPA is not obligated to meet its total requirements. While there is no incentive for zero load growth below that which was forecasted, the allocation does discourage unconstrained load growth. None the less, criticism has been made that these policies are anticonservation since they do not give utilities sufficient incentive for conservation, such as a preference or some other priority on Federal hydro power.

(Note: The smaller preference customers with loads of less than 25 average megawatts have a contractual right to receive their load growth needs from BPA until they reach 25 average megawatts.)

c. Secondary and Surplus Power Sales.

(1) Allocation of Nonfirm Power.

Nonfirm energy is available when there is more than enough water in Federal reservoirs to meet the Federal system's firm energy commitment. The current secondary sales policy calls for the following priorities in the allocation of any secondary energy: (1) All firm energy loads will be served if any are not being met. This includes the bottom three quartiles of the direct-service industrial (DSI) load; (2) new reservoirs will be filled or depleted reservoirs restored; (3) public agencies' secondary power demands will be met, allowing them to refill their own reservoirs or displace thermal generation currently being used to serve their own loads; (4) when not all secondary demands can be met, the remaining energy is split approximately equally between the private utilities and the direct-service industries of the region; (5) after the top quartile of the DSI loads has been met, private utilities in the region can then purchase secondary energy to displace any of their remaining thermal generation which they have declared necessary for meeting firm loads under the Pacific Northwest Coordination Agreement; and (6) after all applicable regional loads have been met, and water cannot be considered for later use in the region, surplus power is made available for sale to the Pacific Southwest over the California Intertie.

It should be noted that this is an extremely dynamic situation and the status of power availability can vary not only from month to month and week to week, but also from hour to hour, depending upon a wide range of variables.

From 1968 to 1978, annual sales to California varied from a low of 0 MWh in 1973 to a high of 17,094,309 MWh in 1976. It is anticipated in future years that as the margin between projected loads and energy available under good water years declines, decreasing amounts of surplus energy will be available for sale outside the region.

Allocation priorities for surplus sales outside the region are similar to those inside the region; that is, preference customers in the Southwest have first call on the surplus energy.

However, the Northwest Preference Law (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. Preference customers in the Southwest have preference rights on Federal energy exported to the Southwest but have no preference rights over entities in the Northwest, preference or otherwise (Role DEIS: C, II-2).

The Intertie was a joint construction effort between the Northwest and Southwest, with Federal agencies, private utilities, and public bodies sharing the cost of transmission lines. Surplus energy exported to the Southwest by BPA is Federal energy which would be otherwise wasted because of the lack of a market in the Northwest. Energy exportable to the Southwest by other Northwest entities is that energy resource which is excess to the entities' needs and is available to California at applicable nonfirm rates. In either case, except for energy acquired through Canadian storage (most of which is now recalled for Northwest use) and a part of Centralia output, energy for which there is a market in the Northwest, at a rate not less than the prevailing rate, may not be exported to the Southwest.

The interties are used for sales of peak power to the Pacific Southwest. Contracts for sales of peaking to the Pacific Southwest require that the energy sent down be returned within a week or paid for in cash if it is not needed in the Pacific Northwest. The Northwest also benefits from peak-energy exchange contracts which provide the region with 343 average annual megawatts of firm energy.

(2) Impacts of Secondary Energy Sales.

(a) Generation Resources.

Planning studies developed to determine the generation needed to serve regional power requirements on a firm basis consider only critical period energy capabilities and January 1937 peak capability of proposed projects (Role DEIS: C, IV-113). Therefore, availability of secondary energy has not strongly influenced the choice of type, size, or location of the next increment of generation required on the power system in the Pacific Northwest. It has influenced coal supply contracts to some extent, and BPA is now studying whether use of secondary energy with combustion turbines might be an effective means of meeting a part of the region's future load growth.

(b) Rates.

Sales of firm power are the basic source of BPA revenues. Sales of secondary energy are the variable element in the total volume of revenue collected by BPA from power sales during any given year. Since rate structures are based on projected long-term revenues, any significant and lasting change in projected revenues will alter rate levels and possibly rate structures. Rates are designed on the basis of projected demand and availability of firm resources, both hydro and thermal, and on average secondary power resources and demand.

In the case of the latter, probable revenues from hydro resources are determined by the average flow of the Columbia River system and for thermal resources based on probable output from each plant. On the basis of present load forecasts and firm and secondary generation capabilities, long-term revenues from firm sales would have to be increased approximately 25 percent if secondary sales were eliminated. The effect on rates to firm power customers if secondary sales were eliminated would depend on the cost to provide these sales and the repayment requirements for transmission and generation. Apportionment of a cost increase to firm load customers would vary depending upon the allocation method selected. If it were a proportional increase, all customers would pay an extra 25 percent. If the allocation were based on a cost-of-service study, the allocation of the increase among customers would vary. These figures would include revenues from secondary sales both inside and outside the region. See Table IV-9 for a breakdown of energy delivered and revenue received during Fiscal Year 1978 from secondary sales.

(c) Environmental Impacts of Secondary Energy Sales.

Due to the contracts and operating cost characteristics of thermal large scale generation, it may not be cost-effective to shut down facilities simply to capitalize on available secondary energy. However, utilities have two options for utilizing secondary energy for the benefit of their ratepayers. First, refueling, maintenance, and equipment replacement/repair are scheduled to take advantage of this energy, sometimes with plants not operating for longer periods than would otherwise occur. Second, a utility may operate the plant, selling its output to other utilities or industry both within and outside the region while buying secondary energy to meet its own loads.

The major impact of both options is reduced costs to consumers. The first occurs through lower cost for replacement power when thermal generation is down; the second, through increased revenues to the utilities. In addition, under the first circumstance, environmental costs are significantly lower than if standby combustion turbines were utilized.

If thermal plants are shut down instead of generating power for export from the region, then short-term environmental benefits could accrue from this displacement. The benefits would be the temporary cessation of those adverse environmental impacts (air pollution, noise, water consumption, etc.) which are associated with the operation of the plant which is displaced. The actual impacts would depend on which thermal facility was displaced. Since Pacific Northwest generating plants generally meet stringent environmental standards and since displacement is only temporary, these impacts would not be significant except in terms of fuel savings and economic factors.

However, sales of secondary energy to the Southwest result in displacement of higher-cost oil and gas-fired

TABLE IV-9

SECONDARY ENERGY SALES

	FY 1978			FY 1977			FY 1976		
Northwest Area	kWh (000)	Revenue in Dollars	Mills Per kWh	kWh (000)	Revenue in Dollars	Mills Per kWh	kWh (000)	Revenue in Dollars	Mills Per kWh
Preference	249,818	772,329	3.09	22,724	77,315	3.40	126,162	395,165	3.13
IOUs	8,616,030	27,489,140	3.19	791,764	2,659,476	3.36	4,178,864	13,788,168	3.30
DSIs*	141,870	481,612	3.39	52,257	173,411	3.32	560,850	1,616,881	2.88
TOTAL	9,007,718	28,743,081	3.19	866,745	2,910,202	3.36	21,960,185	74,725,964	3.40
Outside North-West Area	5,046,237	16,934,356	3.36	0	0	0	17,094,309	58,925,750	3.45

* Excludes top quartile of DSI loads.

thermal resources there. This has two significant impacts. First, there can be savings in costly and scarce fossil fuels, assuming the secondary power delivered is derived from hydroelectric sources. Savings in these fuels benefit Southwest ratepayers and preserve the fuels for other uses. Second, shutting down Southwest fossil fuel-fired resources results in a temporary cessation of their emissions of air pollutants. Since much of the Southwest (specifically, the Los Angeles Basin and other urban areas) has severely degraded air quality, these reductions of air pollutant emissions are significant. There are also impacts of lower cost secondary rates to California on rate levels there (Role DEIS: C, IV-82-113).

One final area of impact results from operation of the Columbia River for hydroelectric generation. Operations to provide peak energy cause river and reservoir fluctuations, and require seasonal control and regulation of streamflows. These operational effects disrupt recreational use of the river and impact fish and wildlife in and adjacent to the river (Role DEIS: A, III-4-5). Surplus sales are usually made when flows are high so peaking operations are minimized.

d. Existing Rates.

BPA currently has eight wholesale power rate schedules and three transmission rate schedules. These schedules cover most of the power and transmission services which BPA provides. Some customers purchase power under several rate schedules.

BPA's public agency and Federal agency customers purchase power from the Wholesale Firm Power Rate Schedule (EC-8) and may purchase from the Reserve Power Rate Schedule (EC-9). These schedules contain both a capacity and energy charge. Depending on the purchaser's load factor, the total bill will vary in relation to the amount of demand and energy purchased.

The Industrial Firm Power rate (IF-2) and Modified Firm Power rate (MF-2) are for sales of Federal power to Bonneville's direct-service industrial customers. An availability credit is included under the IF-2 rate schedule to compensate industries whose loads are temporarily restricted. BPA also sells capacity only (F-7 rate schedule) to generating utilities and secondary energy (H-6 rate schedule) to utilities in the Northwest and the Southwest.

Table IV-10 shows the percentage of power revenues Bonneville receives from each of the current schedules. The current rate forms and rate levels establish a base from which to evaluate impacts of the different rate alternatives which are described in the preceding chapter. The primary impact that will result from rates will be due to the new rate levels and not to rate structures.

The rate levels are established by the revenues which BPA must collect to meet its repayment requirements. This includes repaying the Federal power investment in the Federal Columbia River Power System, with interest, over a reasonable number of years,

TABLE IV-10

PERCENTAGE OF REVENUES BY RATE SCHEDULE
(based on FY 1981 forecasted sales
1979 wholesale rates)

Rate Schedule	Percent of Total Revenues
Wholesale Power Rate, EC-8 (Includes deliveries to public agencies, Federal agencies, and Investor-owned utilities)	48
Industrial Firm Power Rate, IF-2 (Includes deliveries of nonfirm energy to DSI's and availability credit adjustment)	22
Nonfirm Energy Rate, H-6 (Excludes deliveries of nonfirm power to DSI's)	19
Firm Capacity Rate, F-7 (Excludes Supplemental and Entitlement Capacity)	5
Wheeling and Fixed Contracts	5
Miscellaneous and Supplemental	1
Total	100

and recovering other costs and expenses incurred by BPA, including purchased power. As a result, the repayment requirement establishes the total amount of revenue which must be collected. Existing authority precludes BPA from establishing a revenue level based on marginal cost because revenues would exceed revenue requirements.

The Bonneville Project Act requires that BPA review the adequacy of its power rates at least once every 5 years. Historically, contracts negotiated between BPA and its customers provided that rates could be changed only on December 20 of every fifth year. However, as more costly hydro peaking resources were developed and with purchase of the output of more expensive thermal plants, it became evident that 5 years was too long an interval between rate adjustments. Consequently, BPA negotiated revised power sales contracts to allow rates to be reviewed as frequently as once a year if necessary. This provision will take effect on July 1, 1981. More frequent rate reviews will permit a series of smaller rate increases rather than infrequent large increases. Following the December 20, 1979, rate increase, BPA has reviewed the need for another increase for a possible adjustment on July 1, 1981. BPA's rates are filed with the Federal Energy Regulatory Commission for final confirmation.

BPA's current rates produce revenues which are approximately 90 percent higher than the revenues produced under the 1974 rates. Since 1974, there have been significant increases in the costs of operating and maintaining the Federal power projects and in constructing new generating projects and additions to the BPA transmission system. Another significant change is that enactment of the Federal Columbia River Transmission System Act in October 1974 placed Bonneville on a self-financing basis under which it must finance the construction of new transmission facilities through the sale of bonds to the U.S. Treasury. Pursuant to the requirements of the Transmission System Act and the criteria established by the Treasury, Bonneville must pay a rate of interest on the bonds comparable to the current market rate for bonds of comparable quality sold in the money market. This has resulted in increased interest costs to Bonneville compared to the rates of interest previously paid the Treasury on appropriated funds. There have also been substantial increases in the costs of nuclear powerplants of which Bonneville has acquired a share of the capability. These costs increases have been due to a combination of factors, including inflation, higher interest rates, changes in regulatory requirements, construction delays, labor disputes, etc.

The 90 percent overall revenue increase produced a range of rate increases from approximately 80 percent to 140 percent for BPA's customers because of changes in the relationship between demand and energy charges (Rate EIS: V). In general, the impacts of the 1979 wholesale rates are due primarily to higher rate levels rather than to different rate structures. A rate increase by BPA has a direct impact only on BPA direct-service industrial customers and some Federal agencies. The bulk of the impacts from the rate increase are felt indirectly at the level of end-use by households, commercial establishments, and industries. The impacts on end-use consumers are dependent on how BPA's utility customers pass on the rate increase in their rate structures. The impact depends, to a significant extent, on the portion of the utility's total costs are due to power purchases from BPA.

A BPA rate increase has significantly less impact on those utilities with a small percentage of total costs represented by BPA power purchases, than on those utilities with a higher percentage of their costs from BPA power purchases. However, several generalizations can be made about the probable impacts of the 90 percent revenue increase.

1. A 90-percent revenue increase would result in a .9 to 2.8 percent decrease in the loads by 1994 below that they otherwise would have been without the increase. This is due to a response to the increase in the price of electricity.

2. Of the reduction in consumption, about one-third would be the result of conservation and about two-thirds would be the result of switches to other energy sources such as fuel oil and natural gas.

3. Low income consumers would receive the greatest real impact because a greater portion of their budgets is used for energy purchases than is the case of the average income consumer.

4. Heavy energy users, such as aluminum firms, would be affected more significantly than other industries because electricity is a larger portion of their cost of production.

BPA's December 1979 wholesale rate increase results in higher costs for BPA preference utilities. To the extent that these costs are passed on to their customers, the disparity of rates between public and private utilities is reduced as a result of the BPA rate increase. There are several factors which cause differences in the cost of power between public systems and private systems, and among public systems. The cost of power is an important element in the electricity cost equation. Thermal costs are much higher than hydro costs and most private systems have a greater portion of their resource from thermal generation than do public systems that obtain much of their supply from BPA. Other factors which can cause higher costs for private systems include income taxes, higher interest expense, and the requirement that these utilities earn a return on investment.

Another important factor which will cause a rate disparity is the concentration of the distribution system. Systems which are spread over a wide geographic area have higher unit costs to serve customers. In some cases a high distribution cost for a public system will cause the electric rates for its customers to be higher than for customers of private systems which generally cover urban areas. Additionally, there may be small differences among utilities due to financing differences of PUD, cooperative, and municipal systems.

e. Direct-Service Industries

(1) Introduction.

Since 1940 when service was initiated to the ALCOA aluminum plant in Longview, Washington, BPA's direct-service industrial customers have played a fundamental role in the development of the regional power system. In the early days of multi-use dam development on the Columbia River and its major tributaries, the DSIs utilized large blocks of power from the hydro facilities which were excess to regional utility needs. This resulted in the dams becoming cost-effective at an earlier date, reduced capital investment, increased regional revenues, and lowered overall regional rates. The DSIs also provided a market for secondary energy not usable by utility customers due to its unpredictable availability.

In 1965 when BPA no longer had adequate firm hydro capability to meet DSI demand and the region was beginning the transition to a mixed hydro-thermal system, the DSIs signed the first modified firm (MF) power contracts. Under these contracts BPA had restriction rights on certain amounts of DSI contract demand. At this time the DSIs assumed the responsibility for providing a portion of the region's power reserves. In 1971, as Phase 2 of the Hydro-Thermal Power Program (HTPP) was being developed, BPA adopted a new industrial sales policy embracing the principles of industrial firm (IF) power. This industrial sales policy was an essential element of Phase 2 of the Hydro-Thermal Power Program as an incentive to execution of the contracts between BPA and the DSIs and between BPA and the preference customers. Under this policy, BPA received additional rights to restrict service to provide for increased regional reserves. In exchange, the DSIs were to receive long term power contracts in an era of decreasing power availability. In 1975 BPA signed interim agreements with the DSIs for industrial firm power. Prior to the execution of agreements, BPA had contracted with Alumax Corporation for a change in point of delivery and had introduced the terms of those interim agreements contingently. The aspects of the Alumax contract, both for the site-specific impacts from the changed point of delivery and the contingent contract provisions will be examined in a separate EIS presently being developed by BPA. That EIS will utilize material in this EIS. The agreements utilized for the first time the quartile arrangements.

A court challenge to Phase 2 of HTPP, however, halted the subsequent signing of the new 20-year IF contracts until completion of this EIS. Since that time, BPA has been operating under the interim agreements which can be terminated by either party with 30 days' advance notice. If the IF contracts were terminated, service would be continued under the MF contracts.

At the present time, BPA does not have a proposal for long-term service to the DSIs. In 1976, the companies were notified that their contracts would not be renewed upon expiration of their modified firm power sales contracts due to lack of resources to meet load. BPA anticipates continuing to operate under the interim agreements, allowing service to each company to terminate on the expiration date of their modified firm power contract. These dates as well as each company's contract demand are presented in Table IV-12. (For informational purposes and in response to RDEIS comments, Figure IV-3 and Table IV-11 have been provided.)

BPA is currently developing an allocations policy which will address future service to all of the region's customers, including the DSIs. Discussion in this document is limited to the existing contracts. This section identifies and discusses the provisions of both the modified firm and industrial firm power contracts and the impacts of these sales on the power system. Site-specific impacts of the plants themselves are covered at the end of the section. (A detailed history of service to the DSIs is included in Appendix C of the Draft Role EIS.)

At the present time BPA sells power directly to 15 industrial corporations with a total of 21 plants. Six plants are in Oregon, 13 are in Washington, and two are in Montana. Ten of the plants produce primary aluminum metal and account for approximately 90 percent of the direct-service industrial load. As of March 1, 1979, the DSIs had a contract demand of approximately 3400 MW of IF-1 power.

(2) Power Sales Contracts.

(a) Industrial Firm Power.

Industrial firm power (IF) agreements provide Bonneville with several different restriction rights which provide certain specified reserves. While each kilowatt of the DSI contract demand is subject to the different types of reserves provided by Bonneville's restriction rights, the IF agreements divide the DSI contract demand into quartiles for ease of administration. Each quartile has different conditions under which service can be interrupted to provide reserves to Bonneville.

Top Quartile: At any time for any period for any reason. BPA will give as much notice as possible.

This quartile is served from secondary energy available only on an intermittent basis and is frequently interrupted. When prudent operation dictates the top quartile of the IF load be interrupted to ensure service to BPA firm loads, BPA will frequently make available Advance Energy. This energy is sold with the agreement the DSIs will return equal energy at a later time if BPA needs it to meet preference customer loads. This is done either through DSI energy purchases from other entities or through load interruption. If, under prevailing conditions, BPA cannot serve the top quartile with Federal power, it acts as a trust agent for the DSIs in the purchase of outside power and, when available, schedules the deliveries onto the power

TABLE IV-11

BPA DIRECT-SERVICE INDUSTRIAL CUSTOMERS
LOCATION, PRODUCTS, AND PRODUCTS' MAJOR USES
1976

Corporation (1)	Location (2)	Products (3)	Major Uses of Products (4)
Aluminum			
Alcoa	Vancouver, WA	Primary Aluminum Nail, Wire & Extrusions	Construction, Transportation Equipment, Packaging, Electronic Components
Alcoa	Wenatchee, WA	Primary Aluminum	" " " " "
Alumax	Umatilla, WA	Primary Aluminum	" " " " "
Anaconda	Columbia Falls, MT	Primary Aluminum	" " " " "
Intalco	Bellingham, WA	Primary Aluminum	" " " " "
Kaiser	Mead, WA	Primary Aluminum	" " " " "
Kaiser	Tacoma, WA	Primary Aluminum and Rod	" " " " "
Martin Marietta	The Dalles, OR	Primary Aluminum	" " " " "
Martin Marietta	Goldendale, WA	Primary Aluminum	" " " " "
Reynolds	Longview, WA	Primary Aluminum Rod & Wire	" " " " "
Reynolds	Troutdale, WA	Primary Aluminum	" " " " "
Other			
Alcoa (N.W. Alloys	Addy, WA	Magnesium	Construction, Alloying of Aluminum
Carborundum	Vancouver, WA	Silicon, Carbide	Industrial Abrasive
Crown Zellerbach	Port Townsend	Pulp and Paper	Heavy Kraft Paper & Liner-Board
Georgia-Pacific	Bellingham, WA	Chloritae and Caustic Soda	Bleaching of pulp and paper
Hanna Nickel	Riddle, OR	Ferro nickel	Stainless Steel
Oremet	Albany, OR	Magnesium, Titanium	Aerospace Industry, paint, valves
Pacific Carbide	Portland, OR	Calcium Carbide	Acetylene production
Penwalt	Portland, OR	Chlorine and Caustic	Bleaching of pulp and paper
Stauffer	Silver Bow, MT	Elemental Phosphorus	Fertilizer
Union Carbide	Portland, OR	Ferro manganese, Calcium Carbide and Ferro Silicon	Alloying of steel, Acetylene production

Source: Data in table is based on direct-service industrial customers' responses to a questionnaire prepared by BPA in January 1976.

TABLE IV-12

DIRECT-SERVICE INDUSTRY CONTRACT DEMANDS
AND EXPIRATION DATES

DSI	Contract Expiration	Industrial Firm Power Contract Demand 1/ (MW)
Union Carbide Corp.	5/81	12.0
Crown Zellerbach	8/83	13.6
Georgia-Pacific Corp.	7/84	27.0
Intalco Aluminum Co.	10/84	409.33
Carborundum Co.	12/85	29.75
Pennwalt Corp.	12/85	45.33
Alumax - Pacific	7/86	320.0 4/
Kaiser Aluminum - Spokane	10/86	670.0 3/
Kaiser Aluminum - Tacoma	10/86	670.0 3/
Kaiser Aluminum - Trentwood	10/86	670.0 3/
Reynolds - Longview	12/86	689.5 3/
Reynolds - Troutdale	12/86	689.5 3/
Alcoa - Vancouver	6/87	520.0 3/
Alcoa - Wenatchee	6/87	520.0 3/
Alcoa - Addy	6/87	520.0 3/
Anaconda Aluminum Co.	8/87	378.6
Martin Marietta - The Dalles	2/88	409.067
Martin Marietta - Goldendale	2/88	409.067
Stauffer Chemical Works	4/88	79.8
Ormet	5/88	7.0 2/
Hanna Nickel Smelting Co.	6/90	113.28
Pacific Carbide & Alloys Co.	9/91	8.0
		3,412.257

1/ Contract demand is the specific number of megawatts that the customer agrees to purchase and BPA agrees to sell under the conditions of a contract. Contract demands on September 1, 1979.

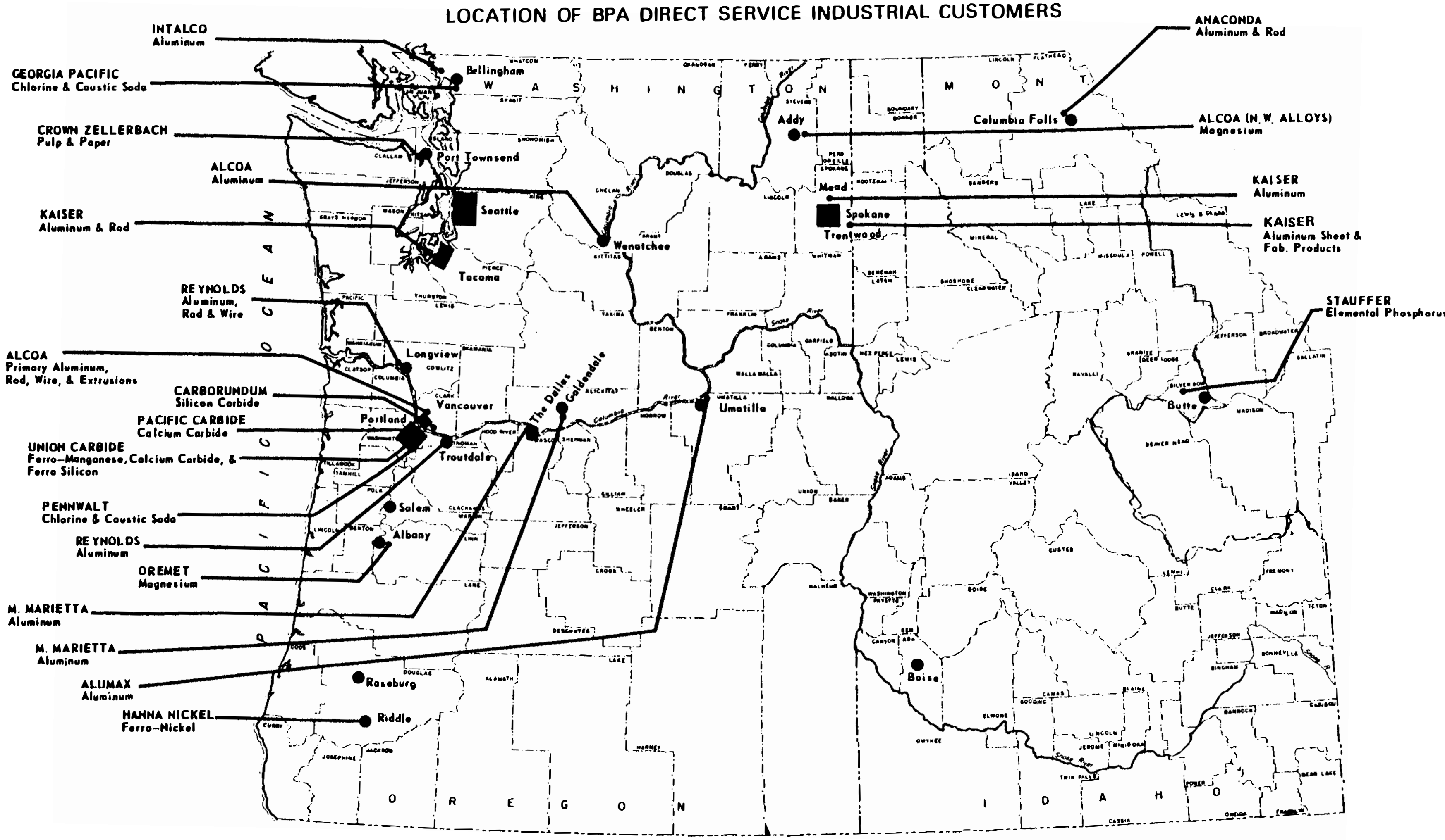
2/ Ormet reduced from 9.0 MW to 7.0 MW on November 30, 1979.

3/ They split demand among plants as they like.

4/ ALUMAX will not take any power before July 1, 1981.

FIGURE IV - 3

LOCATION OF BPA DIRECT SERVICE INDUSTRIAL CUSTOMERS



system. (Appendix A of the Draft Role EIS discusses provisional or advance energy in depth.)

> Second Quartile: To the extent BPA is otherwise unable to meet its firm power obligations because of delays in commercial operation of new generating units or inability to operate any new unit at design capability. BPA must give notice by June 1 of any year in which this is invoked, and provide as much notice as possible of actual restrictions. Such restrictions must be made on a pro-rata basis among the DSIs.
>
> Also to the extent necessary to minimize restrictions of firm power as a result of system stability problems or forced outages of Federal system facilities; includes transmission facilities, Federal generating plants, or generating plants from which BPA acquires power. No notice is required. Total restriction for forced outages in kWh under this category in any calendar year shall not exceed 375 multiplied by the Contract Demand.

The second quartile is considered a part of the region's firm energy load. Because it is part of BPA's firm energy load, BPA makes every effort to serve this quartile. To date, it has been interrupted only in times of system emergency (forced outages). However, as regional loads grow and thermal plants continue to be delayed, without the development of new regional resource programs, service under this quartile is placed in jeopardy. It currently appears that it will be necessary to give notice of interruption for the 1980-81 through 1983-84 operating years for restriction of up to the full quartile. If this occurs, it is likely the DSIs will terminate the IF agreements.

> Third quartile: 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 restriction instead of such a purchase.

This quartile is also part of the region's firm energy load and was designed to provide the region with both reserves against plant delays and additional financing capability for regional resource development. However, under the 30-day interim agreements this quartile is not viable since Bonneville cannot now offer the opportunity to purchase part of the output of a generating plant. Until BPA adopts a new allocation policy, future service to the DSIs is uncertain, leaving no incentive for the DSIs to participate in third quartile arrangements. Therefore this quartile of demand can be considered firm for the duration of the existing contracts, except for short-term restrictions for system stability as noted below.

> Fourth Quartile: None except as for interruption of total load as discussed below.

Under the same conditions of system stability as identified under the second quartile, BPA can interrupt without notice:

1. All the load except that required for plant security for up to 5 minutes to maintain stability.

2. One-half the load for up to 2 hours in any day. Total restriction in kWh under this category in any calendar year shall not exceed 50 multiplied by the Contract Demand.

Authorized Increase: This class of nonfirm power is provided for on some DSI contracts. It is not included in IF contract demands and is served under essentially the same conditions as the top quartile of IF power with the following exceptions; Authorized Increase will be restricted prior to restriction of top quartile of IF power, and Advance Energy will not be made available for Authorized Increase. The Authorized Increase contract section provides for an increase in industrial loads of 1 percent per year accumulatively, from July 1, 1978, through the term of the contract, of the industrial purchasers maximum demand for IF power. These increases in plant loads, for technological reasons other than plant expansion, are restricted to: improvement in the operation of the equipment installed in the purchasers plant, modification of such equipment, installation of additional auxiliary equipment, and installation of environmental protection equipment.

If any portion of the Authorized Increase is converted to IF power, it becomes subject to the restriction provisions of second quartile of IF power listed above.

In the event service to the DSIs is interrupted, the IF contracts contain a rate availability credit. This credit reduces the rate paid by the DSIs as power availability decreases. Basically, as the percentage of IF contract demand served by Bonneville decreases due to Bonneville's exercise of restriction rights, the rate paid by the DISs for the power actually provided decreases. The availability credit does not apply if advance energy is provided.

(b) Modified Firm Power.

Modified firm power contracts (MF) differ from industrial firm power contracts in three areas: BPA's ability to restrict service, the rate availability credit, and advance energy.

The interruptibility arrangements under the modified firm power contracts are more limited than with the IF interim agreements. The top quartile (which is served with secondary energy) remains interruptible at any time for any reason. The remainder of the MF load can be restricted only:

To the extent necessary to minimize restriction of firm power as a result of system stability problems or forced outages of Federal system facilities, including transmission facilities, Federal generating plants, or generating plants from which BPA acquires power. No notice is required. Total restriction for forced outages in kWh under this category in any calendar year shall not exceed 500 multiplied by the Contract Demand.

Additionally, MF contracts contain no provisions for rate credits when power is available less than 100 percent of the time.

Finally, the MF contracts contain no provisions for advance energy sales. Sale of advance energy under MF contracts energy would require new contracts to replace the provisional sale contracts which expired in 1974.

(3) Impacts on the Power System

(a) Operations.

Under the IF and MF contracts, the DSIs have a significant impact on operations of the regional power system. In addition to providing a market for reserves which is unique to the Northwest, their extremely high load factor allows BPA to more easily meet minimum river flows during utility light load hours, to provide for interregional energy exchanges, and to more efficiently operate regional baseload thermal facilities. Finally, through advance energy sales, the DSIs allow for higher utilization of the river system's power capabilities.

Reserves - In the rest of the country energy and capacity reserves are provided by idle or excess generation of various types. This generation is utilized only occasionally. In addition, utilities plan to build resources ahead of need to allow for construction delays, etc. All of these reserves are costs to utilities and therefore to ratepayers. In the Pacific Northwest, reserves are provided by the use of restriction conditions in Bonneville's contracts with the DSIs, as well as by standby generation. These restriction conditions allow Bonneville to sell energy and capacity which otherwise would be idle to provide reserves, resulting in more efficient use of resources and adding revenues to the system. Without the restriction conditions the energy and capacity provided under the DSI contracts would be unavailable to the DSIs since Bonneville would have to hold such generation as reserves. The restriction conditions also allow the DSI's to adjust their operations to reflect market conditions for their products. Reserves provided by the DSIs include:

Operating Reserves: In daily operations, BPA is required to maintain a minimum generation operation reserve to ensure reliability in the event generator or transmission outages jeopardize service to customers. The amount of operating reserve carried during each hour of operation, as prescribed by the Western Systems Coordinating Council, is a function of the magnitude and mix of generation resources on-line during any given hour. An amount of generation equal to the sum of 5 percent of the total hydro resource in use plus 7 percent of the total thermal resource in use, must be available at all times for emergency operations. Operating reserve requirements at current levels of development reach about 800 MW over peak load hours.

At present, BPA fulfills one-half of its operating reserve requirement by maintaining unloaded hydro generating capacity at numerous plants around the Federal system. The remainder of BPA's operating reserve requirement is covered by the interruptible provisions of direct-service industrial power agreements.

Forced Outage Reserves: Unexpected outages of generating facilities are one of the types of events which utility planners and operators must take into account. To provide for such outages, planners add a "forced outage reserve" to the amount of capacity which they otherwise would need to construct. The amount of forced outage reserves required depends upon the type of generation developed. BPA sells a portion of this "excess capacity" to the DSIs, primarily in the first and second quartiles of the IF contracts. BPA also has the right to restrict service to all the DSI load for up to 5 minutes for system stability. BPA has protective relays, including under frequency relaying, on the industrial ties. This automatic load shedding for industrial customers provides the system with extra flexibility in avoiding such events as the cascading blackouts experienced in the northeast section of the country.

Reserves for Plant Delays: In recent years, generating plant construction programs have been plagued by delays. This then leaves utilities, including BPA, in the position of having inadequate resources to meet firm contract demand. The second quartile provides BPA with reserves against plant delays enhancing BPA's ability to meet loads. It allows BPA to interrupt industry loads to meet firm load deficits caused by Phase I hydro and net-billed thermal plants. This restriction right is subject to the termination provisions of the Interim Letter Agreements.

The third quartile was intended to extend these plant delay reserves to the regional system as a whole. By agreeing to trade the third quartile of their contract demand for an equal amount of new thermal generation, the DSIs expanded the region's plant delay reserves to cover all generating facilities in which the DSIs were contract participants. If a plant did not operate as scheduled or up to full capacity, BPA could interrupt the third quartile of the appropriate DSI load to meet firm power demand in the amount the DSI was committed to provide.

Third quartile plant delay reserves differ from the second quartile in several ways. First, non-Federal resources are involved whereas the second quartile is limited to plants in which BPA is a participant. Second, individual DSIs are able to decide which resources to participate in, with the opportunity to reject a specific resource proposal. The companies can also act on their own (subject to BPA approval) to secure regional resources and firm up the third quartile. The second quartile groups the DSIs together, interrupting all if necessary on a pro-rata basis to meet shortages resulting from delays at any of the Federal system resources.

Finally, the IF contracts limit DSI participation to 50 percent of a plant's output unless the DSIs request otherwise and limit the obligation for a single resource to a 5-year period. There are no such limits in the second quartile. Under the 30-day interim agreements this quartile is not viable since the Federal System cannot now offer the opportunity to purchase part of the output of a generating plant.

Peaking Reserves: Peaking reserves are provided in the 2 hour interruption clause. Without the ability to shift this power from the DSI to utility loads during peak periods, the region would be required to either construct additional peaking resources or face curtailments. These reserves are expected to be more frequently utilized during peak months because of large projected peak resource shortages.

The industries have also provided a "reserve" conceptually different than the ones previously discussed, i.e., a demand reserve for firm power available on a short-term basis. Hydro plants on large rivers (such as the Columbia) as well as thermal baseload facilities are generally built large due to economy-of-scale. The blocks of power produced by these plants are generally greater than the immediate or short-term load growth needs of the sponsoring utilities. The industries have historically provided a market for this incremental surplus making the facilities cost-effective and economically viable at an earlier date. The third quartile continues to use this feature of the DSIs. In addition to increased revenues, the guaranteed market for the short-term surpluses provided by the DSIs has the effect of throwing the financial credit of the industries behind the resources being developed. This is important to the power system, as many of the region's utilities do not have significant amounts of system equity to use in funding new resource development, and under current law the regional investment in the FCRPS cannot be used. Without this financial support, resources would be both more difficult and more expensive to finance. (See Section IV.B.1. for a discussion of utility equity and regional resource development.)

In spite of the current inability to implement the provisions of the third quartile, the basic concepts it supported are still viewed by BPA as desirable. Regardless of the regional structure adopted or whether new resources are financed or built through Federal participation, by preference customers as non-Federal resources, or by the region's investor-owned utilities, the region's utility consumers will need reserves against delays in resource development or failure of resources to perform as anticipated. In addition, a guaranteed market for any incremental power temporarily surplus to the utilities' needs will make resources easier and less expensive to finance.

Load Factor - Industrial loads have a definite impact on power system operations in addition to reserves. The DSIs have a load factor approaching 98 percent compared to a typical utility load factor of 55 percent. This base during light utility load hours enhances BPA's ability to meet minimum flows established to protect nonpower river uses. This aspect of services becomes more and more important as the shift from a hydro to a thermal base proceeds, due to the technical, economic, and environmental desirability of steady operation of thermal facilities.

The high load factor of the industries also enables BPA to accept return of peaking energy, providing substantial amounts of energy to the Federal System and reducing the likelihood of spilling water during low utility demand periods, while meeting minimum river flows, thus protecting nonpower uses.

Without the interruptibility of the industrial load, BPA's firm peak load carrying ability would be substantially reduced. In daily operation, twice the amount of hydro generation that is presently used to meet minimum reserve requirements would need to be set aside. If BPA maintains the current level of peak sales, including the total industrial load, then additional generation would have to be constructed to fulfill reserve needs. Alternatively, BPA could reduce peak sales to the amount that the reduced level of reserves (nonindustrial) level could support.

Advance Energy - As stated earlier, BPA makes advance energy available to the DSIs, when possible, to avoid interrupting service. Delivery of advance energy does not endanger future service to firm loads since the energy must be repaid if streamflows prove to be insufficient to refill reservoirs. BPA will advance energy to any entity having the ability to repay, if required, within firm energy resources not previously committed to meeting firm load or with a curtailable load. BPA currently makes available about 800,000 MWh of advance energy to industries from U.S. storage reserves. It plans to make up to 2 million MWh of advance energy available to its direct-service industrial purchasers by provisional storage draft at the three additional cyclic reservoirs. This amount of power would serve the interruptible portion of the DSI load for approximately 4 months.

Provisional storage releases from each reservoir may be used for power generation at the power plant, except at Arrow and Duncan, which have no at-site generating facilities, and all downstream Federal and non-Federal powerplants with sufficient turbine capacity. Provisional storage releases generally are required during low-flow periods when they would be usable at most plants. The total provisional storage release to produce 2 million MWh would vary an estimated 7.2 to 10 feet among the six reservoirs.

The concept for advance energy sales originated following completion of the Hungry Horse Project in 1954. Hungry Horse was the first cyclic reservoir on the FCRPS; hence it was the first Federal reservoir for which operating curves, such as an energy content curve, and critical rule curve were developed. The policy at that time was to base the critical rule curve on the lowest runoff of record, whereas present practice uses the second lowest. Both these policies are designed to produce a high probability that the amount of energy forecast will be available and that any additional water will be used to refill the reservoirs if possible. This conservative planning approach not only provides a high probability that the reservoirs will refill, but also that nonfirm secondary energy can be generated.

These high refill probabilities for Hungry Horse Reservoir, coupled with the fact that BPA's industrial customers purchase about 25 percent of their demand as interruptible power, formed the basis for the original provisional energy concept. During the 20-year life of the provisional sales contracts (1954-1974), BPA sold more than 5 million MWh of provisional energy to industrial customers.

About 3 years prior to the expiration of BPA's provisional sales contracts, it became evident the region would experience firm power shortages in the late 1970's and early 1980's. BPA determined that the only way it could be assured of meeting its future firm power commitments was to give its preference customers notice that it would not supply their load growth after July 1, 1983 and to attempt to reduce its firm power obligations during the period in which its load-resource imbalance was most critical (the late 1970's and early 1980's). BPA concluded that the latter could best be accomplished by persuading its industrial customers to give up their existing rights to power in exchange for a lower grade of power. It was recognized that some concessions would have to be made to the industries since existing industrial contracts ran beyond the period in which future large deficiencies were indicated. One incentive offered industries was new 20-year term contracts. The lower grade of service would provide the reserves needed to protect against delayed operation of new generation and other contingencies.

Throughout the contract negotiations, the industries indicated the proposed new grade of industrial firm power from BPA would have to be available about 85 percent of the time over the life of the new 20-year contracts in order to insure economic feasibility of their operations. On the other hand, long-range planning and Operation studies indicated the availability of nonfirm energy for all customers, including industries, would decrease substantially as the five new cyclic storage reservoirs in the Columbia Basin were developed. Since the interruptible portion of the industrial load is served primarily from nonfirm hydro energy, several methods for increasing the availability of hydro energy for the interruptible loads were studied. The most promising scheme was a continuation and expansion of the provisional energy concept.

Studies made by BPA and by cosultants to the industries indicated that nonfirm hydro energy supplemented by delivery of up to about 2 million MWh of provisional energy would provide the 85 percent availability required by the industries. General contract provisions, developed to replace existing industrial contracts, provide that the Administrator may supply an advance of energy of up to 2 million MWh in lieu of restricting the supply of industrial firm power when system conditions would otherwise require such restrictions. Electric energy made available in accordance with these procedures is called "advance energy." Advance energy retains most of the characteristics of provisional energy, except that BPA expects to supply advance energy by proportionally drafting Hungry Horse and the five new cyclic reservoirs below the normal operating levels required for firm power, rather than only Hungry Horse Reservoir, as was done in the original provisional energy contracts.

Environmental impacts associated with advance energy sales are related to the reservoir drawdown. These include reduced availability and use of recreational facilities due to lower water levels; esthetic impacts; decreased desirability of sport fishing resulting from changes in river flows and temperature; inhibited migration of anadromous fish due to temperature changes; and increased fish mortality due to passage through turbines. All of these impacts occur any time a reservoir is drawn down; however, due to the typical mid to late summer timing of advance energy sales, they are exacerbated. There are some beneficial impacts on the environment such as leveling out the annual distribution of outflow from the reservoirs which in turn results in less temperature fluctuation. The additional drawdown serves as an extra protection against possible flooding downstream and against the possibility of having to spill water to maintain flood control space. Spill, besides being an economic waste, also causes nitrogen to be entrapped in the water which is a hazard to fish.

There are also some environmental impacts associated with <u>not</u> making drafts to produce advance energy. Without advance energy sales the DSI customers would probably be required to purchase energy produced by oil-fired generators or reduce their production levels. Both have detrimental effects, one on the physical environment and the other on the socioeconomic environment of the region. In addition, the draft below critical rule curves in anticipation of later refill by streamflows above critical level may result in water being generated rather than spilled.

At the present time the environmental impacts of delivering advance energy are deemed to be acceptable based on studies by the participating agencies. Operating parameters have been agreed upon by the Corps of Engineers, Water and Power Resource Service, and are expected to be agreed upon by the British Columbia Hydro and Power Authority. The parameters agreed upon include: a maximum combined draft from full of 5 feet (combined draft is the indicated first-year critical rule curve for August 31 plus the provisional draft at each reservoir from August 1 through the first Monday of

September); a plan for the return of the advance energy unless the first-of-the-month January-July forecast volume is less than 70 million acre-feet; and a maximum of 8-1/2 feet of draft below the lower of the energy content curve or proportional draft level at each reservoir. (See Appendix A, Chapter III of the Draft Role EIS for a comprehensive discussion of advance/provisional energy.)

(b) Resource Development.

From a system development standpoint, it is difficult to pinpoint the specific impacts of the DSIs. Generally, resources have been planned to meet regional loads, rather than specific loads. The size of DSI loads has allowed for earlier development and maximum utilization of larger energy resources. There is no indication that the industry loads have influenced the type of resource chosen for development or the site locations.

On a number of occasions the question has been raised regarding the impacts of resources developed to meet future DSI loads. To answer this question several factors of the analysis must be clarified. The DSI IF loads will grow slightly through 1983. This is due to conversions of small amounts of nonfirm Authorized Increase (provided in IF agreements) to industrial firm for purposes of plant expansion. The last new DSI contract, with Alumax, was signed in 1966. Additional DSI load growth, for technological reasons other than plant expansion, is accommodated in the IF agreements under the Authorized Increase provisions mentioned under IV.A.2.e.(2)(a). Resources to meet these loads technically have already been constructed or committed. However, over half of these same resources have, as a first priority, been committed to regional preference utility loads. The industries are not only facing a loss of firm power supplies but also a degradation in availability of nonfirm used as reserves for firm.

The lower three quartiles of the loads are included in our operating program. Roughly 2,550 MW of this load represents the output of 2.72-1,250 MW nuclear powerplants or 6.80-500 MW coal-fired powerplants (at 75 percent capacity factors). This generation requirement should be offset by the generation required to replace reserves currently provided by the DSIs, which would otherwise need to be installed. (Section IV.B.2. discusses the environmental impacts of generation resources.)

(c) Transmission.

Since the transmission system is designed to meet peak load requirements, the BPA industrial loads have influenced the design of the transmission system in the same way as have loads of similar magnitudes and locations. The fact that the industrial loads have a high load factor compared with other loads has little influence. Their presence, however, does contribute to higher load factor utilization of equipment installed.

Without these loads, the BPA transmission system would have evolved somewhat differently. Fewer lines and substations would have been constructed and the development of the 500 kV grid would have proceeded at a slower pace. It would still have been required, however, and because of price escalation, its costs would have been higher.

The industrial loads represent some 15 percent of the total Federal and wheeled power transmitted over the Federal grid. The total system loading attributable to the presence of the DSIs, however, is greater than this because of the related loads associated with the presence of the industrial segment. These include employment and energy requirements in commercial and industrial establishments supplying goods and services to the industries and residence energy requirements for direct and secondary employees.

It is estimated that Federal transmission system capability would be some 15 to 20 percent less today without the industrial loads and their associated loads.

(d) Marketing.

Until the development of a final allocations policy or the expiration of the current DSI contracts, only one major decision confronts BPA regarding service to the DSIs. This is whether to retain the interim IF agreements or to revert to the modified firm power contracts. Two major differences exist which must be considered: first, the MF contracts contain no reserves for plant delays as in the second quartile of the IF contracts. Reverting to MF would increase BPA's firm power commitments by approximately 770 MW until major contracts begin to expire in 1984. Second, the 2-hour peak reserves would be lost, threatening system stability during periods of high unanticipated peak demand. Based on these factors, and projected power shortages resulting from plant delays, it is unlikely that BPA would seek to terminate the IF contracts.

The actions of the industries themselves however, are likely to be quite different. If the second quartile service is frequently interrupted, it is highly possible they will revert to MF power to avoid these restrictions. This becomes more probable if advance energy sales are reduced, or recall becomes more frequent.

The following sections summarize the site-specific impacts of the plants. For a comprehensive discussion of these impacts, see Appendix C of the Draft Role EIS, pages IV-143 to 189.

(4) Economic Impacts.

In 1978, BPA's DSIs accounted for 14,540 jobs, with wages and salaries of $354.4 million. Total expenditures in 1978 by these industries in the Pacific Northwest for salaries, freight, supplies, power, materials, and taxes totalled $920.3 million. Electricity used by these firms in 1978 totalled 29.7 billion kilowatthours with a sales value of $92 million. Secondary employment generated by these basic industries served by BPA accounted for an additional 38,000 jobs based on a ratio of 2.6:1 of nonbasic to basic employment. A study completed for the Western Aluminum Producers by A. D. Little, Inc., (1978) reported that regional aluminum industry employment alone was 11,400 with secondary employment of 29,700.

The A. D. Little study also estimated in 1978 that 131,000 workers were employed in Pacific Northwest industries that utilize aluminum directly and indirectly. These jobs, while not strictly dependent on the regional aluminum industry, nonetheless are in part the result of a regional aluminum supply.

The service industries supplying the aluminum and other direct-service customers of BPA have developed and grown with these electroprocess industries over several decades. The local economic importance of the direct-service customers varies substantially within the region. Plants located in urbanized counties with diversified economies have a significant but not critical impact on the county and local economy. Many of the direct-service plants, however, are sited in rural communities with populations of less than 50,000 where the facility often is the main industrial activity. The DSI customer in this less diversified economic setting may well be a critical component of employment, income, and services of the local area. In seven counties in which DSIs plants are sited, these plants directly and indirectly represent between 19 and 50 percent of the total county employment. Impacts approaching 20 percent of all employment in a local area must be assumed to bear significantly on the economic balance of the particular area.

(5) Physical Impacts.

Due to their heavy industrial nature, BPA's DSIs have significant impacts on the region's physical environment. While the most extensive of these impacts occur in the area of air quality, there are also water quality, land quality, and terrestrial environmental impacts associated with their operations. This section briefly discusses the environmental impacts of DSIs in these major areas (Draft Role EIS: Appendix C, pp. IV-143 to IV-189). In addition, State offices of environmental quality maintain detailed files on the environmental implications of plant operations.

(a) Air Quality.

Industrial plants must generally meet two types of restrictions imposed by State or Federal environmental agencies limiting air pollution: (1) they must not cause concentrations of air pollutants in the atmosphere to exceed ambient air quality standards; and (2) they must limit their emissions of air pollutants to quantities permitted for their plant.

Ambient air quality often does not meet standards in major metropolitan areas and heavily industrialized areas because of the large number of pollutant sources concentrated in a limited area. Of BPA's 21 DSI customer plants, 11 are distributed among three such areas. However, the amounts of air pollutants emitted by BPA's industrial customers in each of these areas are a relatively small portion of the areawide totals, and frequently the pollutants emitted in the largest quantities by the industrial customers' plants are not those for which ambient standards are being exceeded.

(b) Water Quality.

The impact on water quality from BPA's DSI customers results from the types and quantities of water pollutants discharged into local receiving waters. The environmental effects of the major pollutants vary with the types of industry and the geographic location in different drainage basins. Four of the DSIs have total water recycling systems, with no discharge to public waters, and consequently no impact upon water quality. The other industrial customers contribute negligible amounts to the existing water quality problems in the region.

(c) Terrestrial Environment.

The DSI impacts on the terrestrial environment depend upon types of air emissions, geographic location, and existing vegetation, wildlife, and wetlands habitat. Utilizing air quality and vegetation standards as a guideline, 19 of the DSI plants have been determined to have negligible impact on the surrounding terrestrial environment. The two DSIs located in Montana have caused fluoride effects upon vegetation, wildlife, and wetlands around their individual plant sites. These impacts are currently being mitigated through the installation of additional pollution control systems at the plants. (For further discussion of impacts of DSIs, see the Draft Role EIS, Appendix C, pp. IV-143-190).

(d) Endangered Species.

Of the eight endangered and threatened animal species found in the BPA service area, only the bald eagle and the grizzly bear inhabit Glacier National Park in Montana, where an industrial customer causes peripheral environmental impact. The Anaconda Aluminum Plant emits fluorides, causing damage to vegetation up to and including an area within the park boundary. Potential damage to these species could occur through fluoride impact upon forest vegetation within the park, although the known affected area is small in comparison to the total habitat requirements for survival of these species. Recent installation of air pollution control equipment and future compliance with the Montana air quality standards will reduce environmental effects to these species from the plants.

(e) Health Effects.

Air pollutants, such as suspended particulates, sulfur oxides, carbon monoxide, photochemical oxidants, hydrocarbons, and nitrogen oxides are criteria pollutants for which national ambient air quality standards have been established. Criteria pollutants, as well as fluorides, mercury, ammonia, and other odorous chemicals may also be emitted by BPA's DSIs (Draft Role EIS: Appendix C, pp. IV-143 to IV-190). Major water pollutants having potential health effects are fluorides, ammonia, chlorine, and organic wastes. However, plants are either meeting standards which are set to guarantee protection of human health, or are on schedules of compliance to meet these standards in the near future. Therefore, major health effects cannot be attributed to plant operations.

3. Transmission.

a. Impacts of the Existing Power Transmission System.

A network of high voltage transmission facilities connects Northwest generating plants with areas in which electrical energy is consumed. In general, the interconnected transmission systems serve as common carriers of electrical power to minimize duplication of systems.

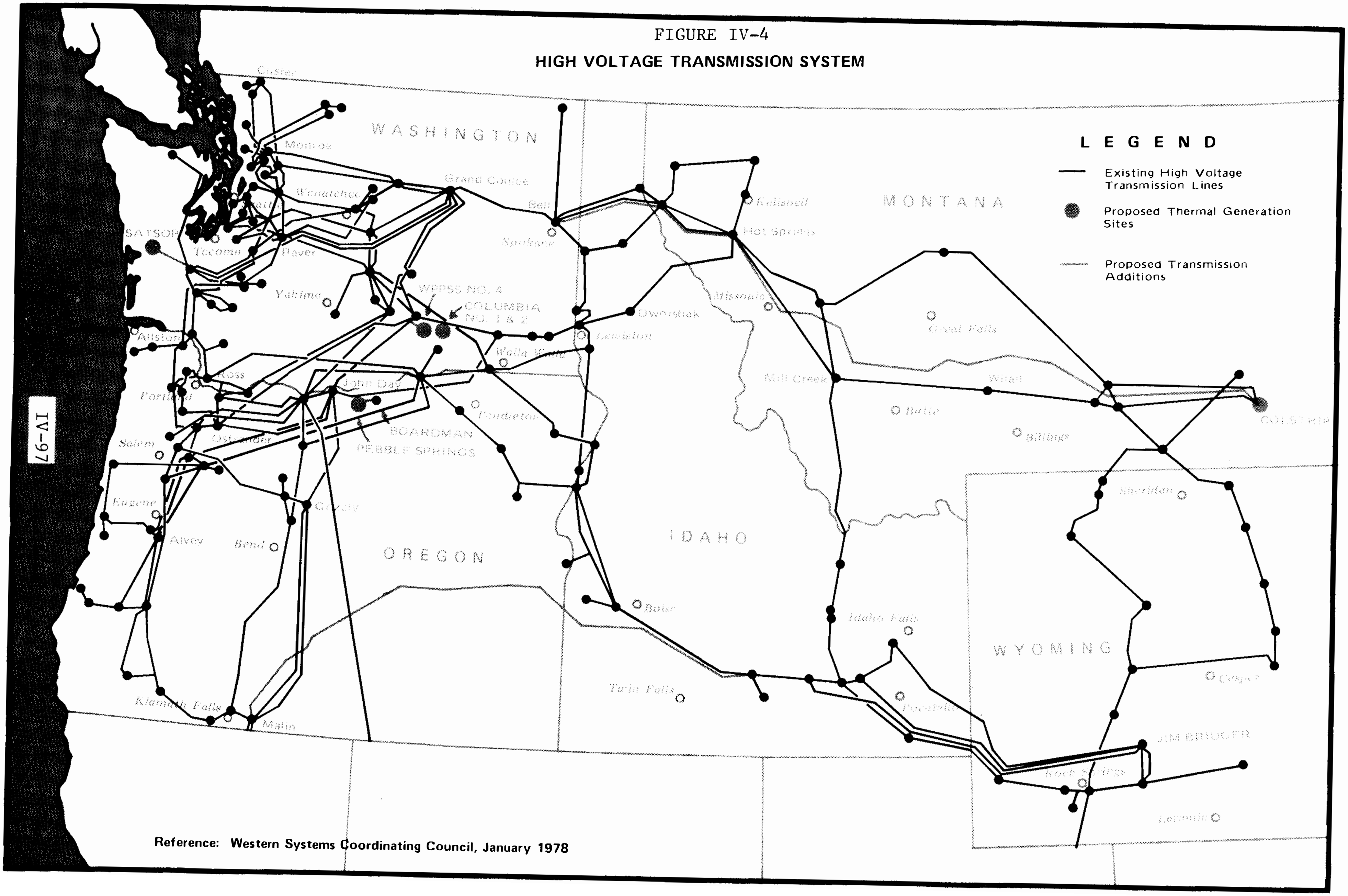
Utilities in the eleven western states coordinate their planning through the Western Systems Coordinating Council (WSCC). The subregion of the WSCC which is most directly influenced by the Hydro-Thermal Power Program (HTPP) is the West Group Area of the Northwest Power Pool (Utah & British Columbia excluded). This subregion and the locations of high-voltage transmission lines within this area are provided in Figure IV-4.

As of January 1979, approximately 16,000 miles of high-voltage transmission (230-kV and above) were in operation throughout this area. BPA transmission lines comprised 8,350 miles of this system, representing 80 percent of the regional capacity. These transmission system statistics include those additions associated with integration of power from the following HTPP-Phase 1 thermal plants: Hanford, Centralia, Jim Bridger 2 and 3, Colstrip 1 and 2, Trojan, and WNP-1 and -2. The following section is directed at the transmission additions required for integration of generation resources authorized subsequent to HTPP-1.

The total land acreage committed to transmission line rights-of-way in the Northwest Power Pool (NWPP) Area has not been calculated by WSCC. As right-of-way widths vary based upon line voltage, line design, and the practices of individual utilities, a precise acreage is difficult to calculate. It has been estimated,

FIGURE IV-4

HIGH VOLTAGE TRANSMISSION SYSTEM



Reference: Western Systems Coordinating Council, January 1978 however, that high voltage transmission facilities within the NWPP Area as a land use currently impact approximately 240,000 acres, which is less than 0.1 percent of the total acreage of this service area. However, the joint use of transmission line rights-of-way for such land uses as agriculture, recreation, transportation, and other utilities is common practice; therefore, these land uses are not necessarily pre-empted by new transmission corridors. However, other activities/uses are pre-empted, e.g., forestland and residential development.

The major components of a transmission system include transmission lines, substations, radio communication and control facilities, and access roads which are utilized for construction and maintenance purposes (Role DEIS: Appendix B, V). The environmental impact of these facilities varies considerably in accordance with their size, location, and voltage characteristics. Typical transmission line physical requirements are provided in Table IV-13, which correlates various transmission line configurations and voltage levels with land use requirements.

TABLE IV-13

TYPICAL TRANSMISSION LINE REQUIREMENTS

	230-kV Single Circuit Line	500-kV Single Circuit Line	500-kV High-Capacity Double-Circuit Line	1,100-kV High-Capacity Single-Circuit Line 1/
Tons of steel per mile	20-40	60-90	150-225	270-340
Tons of conductor per mile	13	32	98	130-160
Transmission capacity				
MW capacity	200	1,500	5,000	10,000
Width of ROW (feet)	90-125	105-160	105-165	160-190
Transmission capacityfoot of ROW width, MW/foot	1.6-2.2	9.4-14.3	30-48	53-63
No. of lines required/ 10,000 MW capacity	50	7	2	1
Costs/10,000 MW/mile of line(s) (comparative costs for line only)	4.2	1.0	0.6	0.5
Acres of land required/ mile of ROW for 10,000 MW capacity	545-760	89-136	25-40	20-23

1/ Developmental Provided for purposes of perspective/comparison only.

Source: BPA, 1976.

Impacts which have been attributed to transmission facilities include:

(1) Air quality impacts due to combustion of construction debris, creation of dust by construction vehicles, and vehicle and exhaust emissions.

(2) Microclimate alteration through the removal of vegetation from rights-of-way.

(3) Accelerated erosion and changes in soil characteristics (primarily during and immediately after construction).

(4) Increased sedimentation of surface water resources due to construction and maintenance activities near such resources.

(5) Alteration of the form, composition, and density of vegetation communities through removal and/or damage during construction and maintenance activities.

(6) Elimination or modification of terrestrial wildlife habitat through vegetation disturbance.

(7) Occasional bird collisions with transmission lines.

(8) Pre-emption of incompatible land uses within rights-of-way.

(9) Interference with land utilization practices such as cultivation and irrigation.

(10) Displacement of buildings within proposed rights-of-way.

(11) Visual and esthetic intrusion upon scenic qualities and cultural resources.

(12) Possible physical alteration of cultural resources.

(13) Temporary population increases during project construction.

(14) Noise impacts from construction activities and the operation of substations and transmission lines.

(15) Disruption of radio and television reception adjacent to the lines.

(16) The production of minor quantities of oxidants in the air immediately adjacent to the electrical conductors during operation of transmission lines.

(17) Electrical hazards through transmission line failures, or through accidental contact with transmission lines.

(18) Minor biological effects related to the electrical and magnetic fields surrounding transmission lines.

(19) Damage to nontarget vegetative foliage from herbicides used in vegetative maintenance.

(20) Visual impacts resulting from the adverse appearance of herbicide treated vegetation.

Table IV-14 presents a matrix which characterizes the magnitude of transmission system impacts upon regional resources. Impacts are characterized for three transmission activity phases: construction, operation, and maintenance. Many of the impacts attributed to transmission facilities may be successfully mitigated (Role DEIS: B, VIII).

A recent practice within the utility industry and a BPA policy is, where practical, to locate new transmission lines along existing corridors and to replace lower voltage facilities with high capacity transmission lines. This policy minimizes the environmental impacts of adding transmission capacity to the system.

b. The Impact of Integrating Generation Resources Authorized/Committed Subsequent to HTPP Phase 1.

The Western Systems Coordinating Council reported in April 1978 that a net increase of 6,400 miles of high-voltage transmission is planned for the Northwest Power Pool for the period from 1978-1987. Of this total, 3,200 miles of transmission is planned to integrate generation resources which would serve Northwest loads. Of the 3,200 miles, 1,550 miles of high-voltage transmission are either solely or partially attributable to integration of generation authorized since HTPP Phase 1. Figure IV-4 illustrates the tentative locations of these transmission lines. Table IV-15 lists individually those transmission additions which are related to integration of recently authorized or committed thermal plants.

Additional units planned for Colstrip 3 and 4 have not been specifically identified as part of the HTPP. They are included here because their output will serve loads in the West Group Area.

Environmental impact statements or assessments which have been prepared on transmission facilities required for plants authorized since HTPP Phase 2 are identified in Table IV-15. For descriptions of impacts attributable to each transmission line, the reader is referred to those documents.

TABLE IV - 14

Transmission System Impacts On Regional Resources

Impact Characterization Matrix

QUALITATIVE IMPACT LEVELS

- HIGH
- MODERATE
- LOW
- NONE

POTENTIAL IMPACTS	TRANSMISSION SYSTEM: TRANSMISSION LINES			TRANSMISSION SYSTEM: SUBSTATIONS			TRANSMISSION SYSTEM: RADIO COMMUNICATION & CONTROL FACILITIES			For Additional Discussion Refer to: Draft Role EIS-Appendix B
	CONSTRUCTION	OPERATION	MAINTENANCE	CONSTRUCTION	OPERATION	MAINTENANCE	CONSTRUCTION	OPERATION	MAINTENANCE	Page Reference:
Natural Resource Impacts										
Atmosphere	LOW	NONE	NONE	LOW	NONE	NONE	NONE	NONE	NONE	VII–1 to VII–4
Geology, Soils & Minerals	MODERATE	NONE	LOW	LOW	NONE	NONE	LOW	NONE	NONE	VII–4 to VII–8
Hydrology	MODERATE	NONE	LOW	LOW	NONE	LOW	LOW	NONE	NONE	VII–8 to VII–12
Vegetation	HIGH	NONE	HIGH	HIGH	NONE	LOW	LOW	NONE	LOW	VII–12 to VII–13
Wildlife	MODERATE	NONE	MODERATE	LOW	NONE	NONE	LOW	NONE	LOW	VII–13 to VII–20
Resource Use & Socio-Economic Impacts										
Land Use Impacts										
Urban/Residential	MODERATE	NONE	LOW	MODERATE	LOW	LOW	LOW	NONE	NONE	VII–32 to VII–36
Agriculture	MODERATE	NONE	LOW	MODERATE	NONE	NONE	LOW	NONE	NONE	VII–23 to VII–30
Rangeland	LOW	NONE	LOW	LOW	NONE	NONE	LOW	NONE	NONE	VII–31 to VII–32
Forestry	HIGH	NONE	HIGH	LOW	NONE	NONE	LOW	NONE	NONE	VII–30 to VII–31
Visual Impact	HIGH	HIGH	HIGH	MODERATE	NONE	NONE	LOW	NONE	NONE	VII–36 to VII–37
Recreation Impact	MODERATE	NONE	LOW	MODERATE	NONE	NONE	LOW	NONE	NONE	VII–37 to VII–38
Historic/Archeological	LOW	NONE	NONE	LOW	NONE	NONE	LOW	NONE	NONE	VII–38 to VII–40
Economic Impact	LOW	NONE	NONE	LOW	NONE	NONE	LOW	NONE	NONE	VII–40 to VII–46
Other Potential Impacts										
Noise & Electromagnetic Effects	LOW	LOW	LOW	LOW	MODERATE	NONE	NONE	NONE	NONE	VII–46 to VII–56
Chemical Hazards	NONE	NONE	LOW	NONE	LOW	LOW	NONE	NONE	LOW	VII–74 to VII–87
Electrical Hazards	NONE	LOW	NONE	NONE	LOW	NONE	NONE	NONE	NONE	VII–58 to VII–60
Field Effects	NONE	LOW	NONE	NONE	LOW	NONE	NONE	NONE	NONE	VII–60 to VII–72

TABLE IV-15

INTEGRATING TRANSMISSION LINES FOR
THERMAL RESOURCES AUTHORIZED SUBSEQUENT TO HTPP PHASE 1

Utility Sponsor	Transmission Line Name	Requirements	Energization Year	Environmental Analysis (EIS) Reference
Pacific Power & Light Co.	Midpoint-Malin (500-kV Single Circuit)	Length (circuit) 441 miles 702 kilometers Right-of-way 9,400 acres 3,763 hectares	1981	DOI-BLM FINAL EIS, October 1978 "Pacific Power & Light Co. Proposed 500-kV Powerline Midpoint, Idaho-Medford, Oregon"
The Montana Power Co.	Colstrip - Townsend No. 1 (500-kV Single Circuit) (110 miles constructed) Right-of-way 4,400 acres 1,780 hectares	Length (circuit) 245 miles 394 kilometers	1982	"Final Environmental Statement, Proposed Colstrip Project" U.S. Department of the Interior, Geological Survey, Aug. 3, 1979
	Colstrip-Townsend No. 2 (500-kV Single Circuit)	Length (circuit) 245 miles 394 kilometers Right-of-way 4,400 acres 1,780 hectares	1982	(discussed jointly with above)
Bonneville Power Admin.	Hot Springs - Bell (500-kV Single Circuit)	Length (circuit) 160 miles 257 kilometers Right-of-way 2,600 acres 1,052 hectares	1982	BPA-DES-75-51, Sept. 1975 "Draft Facility Location Supplement Hot Springs-Bell 500-kV Transmission Line" Bonneville Power Administration Proposed Fiscal Year 1976 Program

TABLE IV-15 (Continued)

Utility Sponsor	Transmission Line Name	Requirements	Energization Year	Environmental Analysis (EIS) Reference
Bonneville Power Admin. (Contd.)	Townsend-Hot Springs 1&2 (500-kV Double Circuit)	Length (circuit) 396 miles 637 kilometers Right-of-way 3,400 acres 1,376 hectares	1984	Draft Environmental Statement "Proposed Colstrip Project" U.S. Department of the Interior Geological Survey, January 5, 1979
	WPPSS No. 4-Ashe (500-kv Single Circuit)	Length (circuit) 1.3 miles 2.1 kilometers Right-of-way 20 acres 8 hectares	1983	NUREG-EIS-75-012 "Final Environmental Impact Statement Related to Construction of WPPSS Units 1&4" Docket Nos 50-450 & 50-513 March 1975
	Columbia No. 1 Integration Ashe-Hanford No. 2 (500-kV Double Circuit)	Length (circuit) 12 miles 19 kilometers Right-of-way 96 acres 39 hectares	1989	
	Columbia No. 2 Integration Loop to Ashe-Hanford No. 1 (500-kV Double Circuit)	Length (circuit) 4 miles 6 kilometers Right-of-way 33 acres 13 hectares	1992	(See above)
	Satsop-Olympia (500-kV Single Circuit)	Length (circuit) 27 miles 43 kilometers Right-of-way 430 acres 174 hectares	1985	BPA-FES-76-31, Jan 1976 "Final Location Supplement Satsop Integrating Transmission Bonneville Power Administration Proposed Fiscal Year 1976 Program"
				Plans to integrate the Skagit Units now proposed to be located on the Hanford Reservation are tentative. As plans begin to become more certain BPA will initiate environmental studies.

TABLE IV-15 (Continued)

Utility Sponsor	Transmission Line Name	Requirements	Energization Year	Environmental Analysis (EIS) Reference
Portland General Elec.	Pebble Springs-Slatt No. 2 (500-kV Single Circuit)	Length (circuit) 1 miles 1.6 kilometers Right-of-way 15 acres 6 hectares	1991	NUREG-EIS-75-025 "Final EIS Related to Construction of Pebble Springs Nuclear Plant Units 1&2 Portland General Electric Co." Docket Nos: 50-514 & 50-515
	Carty-Slatt (500-kV Single Circuit)	Length (circuit) 17 miles 27 kilometers Right-of-way 207 acres 109 hectares	1980	Environmental Analysis - "Proposed Participation in PGE's Boardmen Coal Plant, Oct. 1978" Pacific Northwest Generating Co. P. O. Box 48, Hermiston, Oregon 97838
Puget Sound Power & Light	Skagit-Sedro Woolley (230-kV Double Circuit)	Length (circuit) 10 miles 16 kilometers Right-of-way 120 acres 49 hectares	1984	NUREG-EIS-75-055 "Final Environmental Statement Related to Construction of Skagit Nuclear Power Project Units 1&2, Puget Sound Power & Light Co." Docket Nos: 50-522 & 50-523, May 1975 Final Supplement NUREG-0235, April 1977 "Environmental Impact Statement on Location of WPPSS Nuclear Project No. 4 Washington Public Power Supply System, July 1974," pursuant to Washington State Environ. Policy Act of 1971, R.C.U. 43.21C.030

Several considerations are noteworthy with respect to the impact of these transmission lines. Double-circuit construction (two circuits on one row of towers) may significantly reduce the linear mileage and consequently, the impacts. For example, transmission proposals integrating these plants which are currently favored by their utility sponsors would result in more than 200 miles of double-circuit construction. Consolidation of proposed lines with an existing line, through construction of a double-circuit line, is being considered in locations where the impact of an additional line would create adverse impacts. An additional factor which minimizes impacts is the location of new transmission lines adjacent to existing lines. Although locations for many transmission lines included in Table IV-15 have not been decided, under current proposals, 738 circuit miles would be located along existing transmission corridors. The impact of integrating these transmission facilities would therefore be much reduced in magnitude from that suggested by the mileage figures cited.

Nevertheless, because of the location of generation resources listed in Table IV-15, transmission considerations are significant. For example, Colstrip is located in an area where the existing transmission system is relatively undeveloped, hence Colstrip 3 and 4 collectively require 848 linear miles (1,046 circuit miles) of high voltage integrating transmission. Jim Bridger 4 is similarly remote. In contrast, the Pebble Springs plant is located adjacent to the existing high voltage transmission grid, and thus its integration will require virtually no additional transmission facilities.

c. <u>Total Impacts of the Transmission System</u>.

In 1987 the power Northwest Power Pool grid is expected to contain approximately 19,200 miles of high-voltage transmission, an increase of 3,200 miles over that presently in operation. The approximate right-of-way acreage throughout the system will increase from 240,000 acres to about 290,000 acres in 1987.

Environmental impacts will increase in nearly the same proportion as will system expansion. The geographical areas most impacted lie in the eastern portion of the Northwest Power Pool since some thermal generation is planned for the States of Montana and Wyoming. Integration of thermal generation located near load centers or the existing transmission grid requires comparatively little power grid expansion.

Each of the transmission line additions planned during the period from 1978 to 1987 will be discussed in a project specific environmental impact statement.

B. Impacts of Future Power System Development.

1. Introduction.

For the purposes of this document, regional cooperation and coordination is defined as: the formalized process of regional decisionmaking employed to develop, operate, and maintain a regional power system in an efficient, economically, and environmentally sound manner, including the consideration and accommodation of both power and nonpower concerns. This interaction includes participation by utilities, state and local government, industries, special interest groups, and the public at large.

As discussed in the overview, the Pacific Northwest is at a crossroads in regional energy planning. Historically, a one-utility approach to system development and operations has been pursued with a high level of participation and cooperation between the region's utilities, direct-service industries, and BPA. For many years, the region's extensive hydro system provided adequate power generation to meet all of the region's energy demands, and generated little public interest. However, in the past decade the situation has changed dramatically. The hydro system is no longer capable of supplying the region's electric energy needs, and the region has turned to thermal generation. Thermal plants have been delayed, increasing the possibility of energy deficits; thermal costs have skyrocketed, creating controversy over who should receive the relatively low-cost Federal power; utilities which have previously depended on BPA to meet their total power needs are faced with obtaining resources to supply future load growth; some of these have little if any system equity to use as collateral, although some equity derives from their supply of low-cost Federal power; public interest in regional environmental and energy issues has heightened; and, as the river has been used to produce increasing amounts of energy, serious conflicts have developed with nonpower uses.

The region has a number of options in addressing these issues, ranging from a reduced level of regional cooperation and coordination from that which has been pursued historically, through a continuation of existing activities, to a <u>formal, structured</u> one-utility approach for <u>all</u> aspects of the power system, including the development of new resources. The proposal and alternatives analyzed in this document are designed to cover this range of options relating to regional cooperation and coordination.

In analyzing the impacts of the proposal and alternatives, three underlying areas of impact can be differentiated, providing the backdrop for specific impacts of system functions and development strategies. First are the general impacts related to varying levels of regional cooperation and coordination; second are the impacts of load-resource imbalances; and third are the effects of nonpower considerations. These three areas are interrelated and provide the basic structure for impact analysis. This section provides a discussion of these interrelationships and their impacts.

a. Regional Cooperation and Coordination.

A unique situation exists in the Pacific Northwest regional power system. In most areas of the country, utilities not only distribute power to their customers but also construct, own, and operate the generating resources. As loads increase, the utilities' equity in existing facilities, together with their ability to generate revenues from rates, is utilized to finance new facilities.

In the Northwest a different system has developed. Due to large geographical area and sparse population, the electrification of the bulk of the region was not attractive to investor-owned utilities, leaving rural areas without electrical power. So, as detailed in the overview, Congress attempted to provide for more widespread availability of power through construction of the Federal dams and establishment of BPA. These actions resulted in the formation of a large number of small nongenerating utilities (BPA preference customers) who distribute BPA-supplied wholesale power at the retail level. As the region's ratepayers paid their bills, a portion of the revenues was used to repay the costs of the Federal Columbia River Power System (FCRPS) and build "regional equity", rather than individual utility system equity.

Although this system worked well during past periods of adequate and excess power supply, it has now run into problems. After 1983, BPA will no longer be able to meet the load growth of the region's preference utilities with existing resources, and under current authority cannot purchase additional long-term power from non-Federal resources. Nor can the FCRPS or regional rate base be used under existing law as equity for the acquisition of power by the region's utilities. The result is that utilities can only rely on the equity they have in their individual systems (which is generally quite small) and the rate leverage they have in their consumers' ability and willingness to buy power. The point is that, in the Pacific Northwest an individual utility's options are extremely limited, due primarily to financial constraints. By working together, utilities' choices are expanded, but Congressional action would be required to revitalize the one-utility concept and allow new resources to be backed with the equity represented in the existing FCRPS.

For the purposes of this EIS, increased coordination implies four fundamental changes in the region's decisionmaking process: (1) greater centralization of energy planning processes for the region; (2) broader formal participation in such planning by State and local governments and the public at large in addition to the region's utilities; (3) a more systematic and comprehensive planning process, including criteria, procedures, and preparation of a planning document; and (4) greater pooling of the region's generation in the FCRPS and its future costs and benefits. These changes are intended to ensure that the region's power resources are planned and operated in the best interests of the region as a whole. The alternative levels of cooperation and coordination presented in the EIS are equivalent to alternative levels of adoption of the one-utility concept for regional power planning, development, and operation.

By focusing on various levels of regional cooperation and coordination and varying levels of authority for BPA, the proposal and alternatives illustrate the range of choices open to the region in future power system development. Each of these various institutional arrangements results in a number of potential environmental impacts.

In analyzing the effects of regional interaction (cooperation and coordination) on power system planning, development, and operation, five major areas of impact have been identified. These areas include:

1. Load forecasting
2. Resource development
3. Utilization of diversities within the region
4. Interregional transactions
5. Institutional and political responsiveness

(1) Load Forecasting.

One of the most important functions of an electric utility is to provide adequate resources to meet its loads. As part of this function it has been the responsibility of individual utilities to develop electrical load forecasts. These forecasts are used to plan for future resource, transmission, and distribution requirements.

All forecasts of electrical loads are uncertain to some degree. This uncertainty increases the risks that the resources developed based on a given forecast will not match the actual demands which occur.

When planning for regionally-oriented resources, it is advantageous to have a regionally-focused forecast developed cooperatively by utilities and other energy interests. This allows for the use of a common set of assumptions, provides the resources for a more comprehensive data base, and builds in a regional range of uncertainties, which can take into account the diversities among individual utility forecasts. Taken together, these factors increase the accuracy of the forecast. A regional forecast would also help resolve the present controversy of contradictory and noncomparable forecasts done by various groups and agencies (e.g., utilities, State energy agencies, universities, etc.), and would allow for better and more timely decisions on resource needs. A regional forecast could also be used in utility and BPA revenue forecasts, and the planning and development of the regional high-voltage transmission grid, interconnections between regions, and distribution systems.

(2) Resource Development.

Regional electrical loads continue to increase. Meeting increasing loads requires the development of additional energy resources (including efficiency improvements in existing resources). The level of regional interaction affects both what type of resources are developed and how they are developed. In general, the greater the level of cooperation, the wider the range of resources available. As discussed in Section IV.B.1.a., each resource category has its benefits and liabilities. Based on these characteristics, the following generalizations can be made on the effect of cooperation on resource selection.

Insofar as large scale generation is determined to be necessary, it will be developed only with a level of regional cooperation at least equal to that currently in existence. This is due to the large capital and financing requirements, lengthy construction lead times, the inability of the region's utilities to individually utilize such large blocks of power, and other characteristics of such resources.

By the same token, without a formal regional program, it is unlikely that any major reliance could be placed upon conservation or end-use resources in long-range power planning. Utilities would tend not be develop these resources because of the difficulty in predicting their effectiveness; the lack of available funds for financing, particularly from public utilities; inability to share the risk of development; and a general lack of power resources to be used as backup if the programs should not achieve projected goals. If no Federal resources were available to provide reserves, load-shaping, or as backup for new resource development, the risks and implications of shortage might be unacceptable for adequate service. Thus, while most utilities undoubtedly support conservation and many will make concerted efforts to encourage energy efficiency, it is unlikely to be treated effectively throughout the region as a long-term firm power resource without a regional program. BPA participation in research and pilot program development, as well as the establishment of allocation policies designed to promote these programs, could encourage development of conservation and end-use resources. Cooperation through a regional program would enhance policy development for these resources.

With a regional program, geographical diversity in renewable resources can make them reliable as firm resources, whereas individual utility service areas would not have the geographic range to capture this diversity. For example, some level of wind energy may be a reliable firm resource regionwide, while in a smaller area, wind may at times be completely unavailable as a firm resource.

Lesser levels of regional interaction can be expected to encourage the development of smaller scale conventional generation. The specific resource technology would depend upon who developed the resource and where. However, coal, biomass, cogeneration, and small-scale hydro appear to be likely choices. Large scale generation would probably be precluded due to cost and economically preferable size.

(3) Utilization of Diversities Within the Region.

Electrical load characteristics vary from one utility to another. Peakloads of different utilities do not always occur at the same time. Yet each utility must have sufficient resources to meet its maximum load. If utilities with different peak times share resources, the total resources required are reduced, resulting in more efficient resource operation. The variation in peakloads is called peakload diversity. Similarly, generating resources vary in the times when their output is available. Resource diversity, like peakload diversity, permits reduction in total requirements if utilities share resources. Individually, utilities are unable to take full advantage of these diversities. Cooperation between regional utilities increases their ability to take advantage of the diversities that exist across the region.

The effects of cooperation in utilizing regional diversities center on efficiency in resource use. Peakload diversity without cooperation requires reserve generation which is infrequently used, such as combustion turbines. Cooperation permits the construction of fewer reserves through more efficient and frequent operations of shared resources, thus reducing their costs and impacts. Resource diversities, primarily forced outage and streamflow diversities, similarly improve the efficiency with which resources are used.

Cooperation also improves the efficiency with which transmission facilities are used. Diversity permits the joint utilization of transmission facilities for wheeling, load-factoring, and exchanges of power and energy among regional utilities, thus transmission capacity is used more frequently, and therefore more efficiently.

The greater efficiency of resource use which cooperation provides through diversity utilization leads to greater flexibility of the power system in accommodating new resources. Renewable resources also are more reliable when coordinated regionally. The region can better utilize the reserves provided by direct-service industries. Overall, resource requirements are reduced, and corresponding costs and impacts of generation are reduced, while at the same time the likelihood of curtailment or of termination of DSI service is also reduced.

(4) Interregional Transactions.

Interregional transactions extend the diversity benefits described above to a larger geographical area. Cooperation within the region facilitates transactions between regions by providing a collective basis for transactions between the pluralistic utility system of the Northwest and the more consolidated systems which predominate in other regions. By acting cooperatively with another region, Northwest utilities are better capable of developing interties and managing their use for optimum efficiency. Resources in both regions involved are used more efficiently and the need for generating capacity is reduced, resulting in economic savings and reduced net impacts of generation in both areas over the long run.

(5) Political and Institutional Responsiveness.

Interest in power development and operations has increased in recent years. Environmental concerns, the rising cost of energy, the movement toward public participation in planning and decisionmaking, and the increasing size of power supply systems have focused attention on the continued development of the regional power supply system. A common complaint has been that interests outside the utility industry lack avenues for voicing their concerns to power planners. Cooperation can provide a common forum through which the interest groups can express their needs. Utilities collectively have opportunities to learn the concerns of these interests, and the interest groups can direct their input to one central forum, rather than attempting to maintain contact with the many utilities in the region.

The important effect of this cooperation is that valid concerns which may not otherwise be known to the utility industry enter the planning process, rather than emerging later and possibly resulting in costs or delays which could have been avoided. In providing a forum for public participation, the regional power system is better able to respond to concerns ranging from those of individual citizens to national energy policy directives.

The ultimate effects of planning the operation of the power system with input from diverse regional interests are that regional preferences can be taken into account in resource development, the risk of delay is reduced, and costs and impacts of power development and operations are similarly reduced.

A prominent example regarding the responsiveness of the power system is the issue of the competing demands for water among power generation, irrigation, and fisheries. Cooperation can provide the means for consensus in resolving the issue, whereas without cooperation, the result is more likely to be resolved through legal action. Cooperation permits reasoned compromises; the absence of cooperation is more likely to result in solutions based on adversary roles.

b. Load-Resource Imbalances.

Since cooperation can aid in achieving load-resource balance, an exploration of the impacts of imbalances may be illuminating. Strictly speaking, instantaneous electrical generation and loads are always in balance; if there is not enough generation, load must be dropped to maintain balance or blackouts will occur. However, from a long-range planning perspective, loads or resource developments may not occur as projected. Therefore, it is possible that electrical demand and generation will not be matched. A load-resource imbalance is a dynamic state, involving a series of strategies which may be adopted in response to an impending imbalance. The impact of a load-resource imbalance varies according to the extremity of the measures which are necessary to match generation to instantaneous demand.

In general terms, a load-resource balance developing from a cooperative regional planning process would mean: optimum operating efficiency of the power system; reliable performance system; optimum utilization of capital, material, and fuel resources; minimization of wasteful long-distance transfers of electrical energy to offset regional deficits and surpluses; reduction of costs and impacts associated with load curtailments and plant shutdowns; reduced costs to ratepayers; and ability to provide assured power allocations to all consumer classes in the region. Environmental and socioeconomic impacts of regional energy resources would more likely result if there were some assurance that sufficient resources would be available to meet regional loads. However, the impacts associated with electric power shortages and resource developments that would exceed regional requirements would be avoided. Moreover, the aggregate level of impacts probably would be considerably less than if loads were not matched by resources, particularly if conservation and renewable resources are developed. Underlying the prospect for load-resource balance is the premise that the region has a variety of energy options available for achieving such a balance, such as conservation and renewable resources, many of which would lead to fewer environmental impacts than a large baseload thermal system would create.

(1) Impacts of Insufficient Resources.

The most direct impact of resource deficiency would be that some loads would have to be curtailed. The degree of curtailment would determine the extent of impacts; at first, losses to production and employment cutbacks to DSIs would be the primary impacts, but as the magnitude of deficiency exceeded DSI interruptible reserves, personal inconveniences to the general public, the use of backup generation and substitution of other energy sources, and economic impacts, such as industrial closures, would occur. A deficient system, by itself, would result in fewer impacts than the larger system which would be necessary to meet loads simply because it would have fewer generators, hence fewer impacts of powerplant construction and generation, but the total effect would be that impacts would be shifted from the power supply system to other areas of the regional economy. The use of fossil fuels as a substitute for electric energy could have significant impacts on air quality, as well as economic effects of impacted fossil fuels.

In the event of resource deficiency, incentives would be strong to operate existing facilities at maximum output. Schedules for maintenance and refueling of generating plants would become more restrictive, and the hydro operations would have to be adjusted to accommodate these tighter maintenance schedules.

Deficiency within the region would create a demand for imports of nonfirm power which, if available, would further add to the use of the hydro system for backup. Impacts of generation would be shifted to whichever region provided power to the Pacific Northwest. Power costs within the region would rise due to the higher cost of imported power. If enough imports were available, but intertie capacity was not sufficient to carry all the imports needed, the demand for additional interties would increase, although the time requirement to construct additional interties might not permit timely development of new interregional interconnections. It is unlikely, however, that intertie capacity would be the limiting factor on the region's ability to import power.

Within the region, stronger incentives would exist for conservation, load management, and the development of alternate resources. Emphasis would be placed on programs which could be implemented quickly, rather than those which were most cost-effective.

Depending on the availability and cost of conservation and imported power, pressure would also increase for the development of generating resources which could be placed on-line within a short time. The choices available would be limited by the urgency of the need for generation, and, as with conservation, emphasis would tend to stress speed of development rather than cost or environmental impact. Development of more costly resources would increase electricity rates faster than if resources were sufficient.

Demands for maximum generation from the existing system would tend to oppose the accommodation of nonpower demands on the operation of the hydroelectric system. Impacts on fisheries, irrigation, and other water uses would likely result.

It should be noted that these impacts would vary greatly with the degree of deficiency. Two characteristics of the present Pacific Northwest power system would tend to mitigate deficiencies. One is the long interval during which a deficiency would develop, based on the use of critical period hydro planning. This period could allow more time for the region to make adjustments in power consumption (such as strict conservation and end-use curtailment programs) to mitigate the impacts of a deficiency. The other is the interruptible portions of DSI loads, which, if they are available to the regional power system, can provide a sizeable buffer between numerical deficiencies and regionwide shortages. These are not a guarantee, however, that serious impacts would not result from a resource deficiency.

The impacts summarized here represent an extreme scenario of resource deficiency. Lesser degrees of deficiency are more probable.

(2) Impacts of Resource Surpluses.

A surplus of generating resources relative to loads would have impacts quite different from those of a resource deficiency. Economic activity in the region would be affected very little; most of the impacts would be borne by the regional environment due to both construction and operation of surplus resources. These impacts would include land use, consumption of material resources, energy input, and increased impacts on air quality and water quality, as well as radioactive emissions, noise, and solid waste. Costs of surplus resources would increase regional power rates.

Environmental impacts of generation insufficiency would be greater than those of a sufficient power system (see Sections IV.A.2.a.2. and IV.B.1.a.&b.). Due to the costs of the excess facilities, rates could increase within the region (see Section IV.A.2.d.).

If the excess facilities were left idle, regional rates would include the fixed costs of surplus facilities, thus rates would increase, but the variable (operating) costs would not accrue and the environmental impacts of operation would be avoided.

It is more probable, though, that excess facilities would be operated to generate power for export. In this case, the Pacific Northwest would bear the impacts of operating the facilities, but the revenue from the sale of export power would mitigate the cost impact. In addition, the environmental and economic impacts of either generation or shortages in the area receiving the power would be reduced. Power exported to displace fossil fuel generation would also have economic benefits to the nation in reducing the need for either costly domestic fuel development or foreign imports.

Depending on the magnitude of the excess of resources, if it were a long-term surplus, pressure could develop to build new interties with other regions. This impact is similar to that of a resource deficiency in that the same facilities are involved, except that in this case, the purpose is export of power rather than import. The environmental impacts of construction of interties would occur in both regions (see Section IV.B.3.b.).

If an excess of generating facilities were short-term, the result might be economically beneficial. Depending on the type of facilities and the rate of escalation in costs, it could be more economical to build the resource at an earlier time. Exports could provide revenues until the plant's output was required within the region. If the excess were long-term, however, the costs of facilities would result in higher rates than in a sufficient system.

c. Nonpower Issues.

Consideration of nonpower issues in power system planning and operation is a function of: (1) the nature of regional decisionmaking (who has the responsibility and authority to make decisions); (2) the degree of coordination between utilities and non-power interests in determining and implementing a mutually acceptable compromise; and (3) the relative priorities given to competing uses of the river as determined by: the ability of the region to meet its electrical load requirements; the types of resources selected; the role of the hydro system; and the need for other water-derived services such as fishing, irrigation, and recreation.

The greater the broad-based regional participation in planning the development and operation of the region's generating system, the greater the possibility that diverse resource interests are reflected in such planning. The more impact nonpower interests have on planning, the more likely they can be accommodated through altered river operations. The greater the interutility coordination in the region, the more likely it is that some form of agreement between utilities and nonpower interests would be reached and implemented in a manner that satisfies both economic and environmental objectives. Conversely, the less interutility coordination, in the absence of legislation or a regional mechanism to mandate new nonpower constraints, the less likely it is that alternative solutions would be reached for accommodating the competing demands of power and nonpower uses of the river. Without a legislative mandate or a regional body empowered to make river management decisions, or without the opportunity to negotiate directly with the region's utilities on an organizational basis, other avenues for resolving nonpower demands would undoubtedly be pursued, resulting in greater political pressures on utilities to accommodate nonpower concerns.

In the event that a lack of regional coordination increases the tendency toward resource insufficiency, existing nonpower constraints might be relaxed over the short run in order to generate additional power. If, on the other hand, resource surpluses relative to loads occur, there is greater likelihood, at least in the short run, that nonpower demands would be accommodated. In other words, the greater the prospect for load-resource imbalances, the more uncertain the establishment of a long-term, stable accommodation between power and nonpower interests, with a corresponding increase in the likelihood of short-term, ad hoc adjustments between the two. In general, without outside intervention from Congress or the States, nonpower interests are likely to suffer in the face of greater uncertainty regarding the region's ability to ensure timely development of new resources.

2. Impacts of Potential Regional Energy Resources.

The descriptions of energy and capacity resources which follow are the basis for regional resource scenarios which are presented in the next section of this chapter. Since in many cases research on resources is still in progress, the information presented here must be regarded as tentative, reflecting the current knowledge of potential resources for the region.

a. Conservation Resources.

(1) Conservation - End-use Technology.

Conservation measures may be classified into the following categories:

b. User/owner actions requiring no or minimal investment in new energy saving equipment or modification of existing energy consuming devices. This could include:

(1) thermostat temperature set-ups and set-backs

(2) reduced hot water use and temperature

(3) reduced lighting levels

(4) recycling

c. User/owner actions requiring retrofit or new construction to improve thermal efficiency of structures including:

(1) insulation and weatherization retrofit

(2) new construction practices or codes to result in more efficient buildings

d. Developing and implementing more energy efficient appliances and industrial processes:

(1) increased appliance efficiency

(2) increased lighting efficiency

(3) conversion of electric resistance space and water heat to more efficient methods

(4) more efficient processess in industrial plants

(5) waste heat recovery

(6) improved irrigation pumping efficiencies

Potential

Comprehensive, detailed end-use data is needed to determine potential regional energy savings from individual conservation actions. Data on factors such as how many and what types of conservation actions have been taken, average insulation levels, and percentages of fuel types currently used for heating are generally not available for the Pacific Northwest. Until such information is available, the following can only be considered as rough estimates of the potential average annual energy savings for the region based on individual consumption patterns. The regional potential in each case represents a hypothetical situation in which 100 percent of the population adopts 100 percent of the actions. Although the numbers represent a theoretical potential, differing consumer participation rates, as well as the influence of existing conservation measures and programs, will cause the realizable potential to be significantly lower than indicated.

a. Low cost or no cost user or owner conservation actions.

(1) Residential Sector.

Reducing thermostat settings from 72°F day and night to 68°F in the daytime and 55°F at night could result in about 12 percent savings in space heating energy. 1/ This represents an estimated annual savings for the region of 3.6 billion kWh.

Adding 4 inches of insulation to a water heater, installing shower flow restrictors, and washing clothes in cold water saves 11, 30, and 13 percent of the water heating energy respectively. 2/ The region could save as much as 12.3 billion kWh annually by 1995 if all the measures listed above were implemented.

Reducing energy consumption for lighting by turning out unused lights, using task lighting, lowering lighting levels, and similar actions can save about 10 percent of lighting loads. 2/ This represents an estimated annual savings for the region of 0.9 billion kwh.

(2) Commercial Sector.

Setting heating thermostats to 72°F and cooling thermostats to 78°F in commercial buildings could save about 967 million kWh of electricity per year in the Pacific Northwest in 1990. 3/ 4/ Additional savings would be achieved by setting heating thermostats back to 55°F when buildings were unoccupied, but quantitative data for these savings are not readily available.

Several studies have discussed energy savings for lighting in the commercial sector but the amount of savings is inconclusive since estimates vary from 15 to 90 percent of the energy used for lighting. 5/ 6/

(3) Industrial Sector.

The maximum potential energy savings from industrial low cost conservation or housekeeping measures such as improved lighting, reduced thermostats, computer control of industrial processes, etc. in the Pacific Northwest is estimated to be 112 trillion Btu by 1990. 7/ (This includes all energy forms, not just electricity.) Sufficient data to identify only electricity savings is not available.

(4) Recycling.

Recycling could save 27.9 trillion Btu per year of energy of all forms by 1990, 8/ based on household waste plus an allowance for commercial, industrial, and civic waste valued at 68 percent of the household generated waste. 9/ There is insufficient data to separate electrical savings from those of other energy forms.

b. User/owner actions relating to retrofit or new construction.

The following conservation measures have particularly high conservation effectiveness in relation to costs:

(1) Retrofitting existing electrically heated residences with optimal insulation levels, weatherstripping, and storm windows. This could save about 2.0 billion kWh per year in 1990 in the Pacific Northwest. 10/

(2) Constructing new residences in accordance with the ASHRAE 90-75 insulation standards could save 1.9 billion kWh per year in the Pacific Northwest in 1990. 11/

(3) Retrofitting existing electrically heated commercial buildings by adding insulation to walls and roofs and by double glazing windows could save over 3 billion kWh of electricity per year in 1990 in the Pacific Northwest. 4/ 12/

(4) Constructing new commercial buildings in accordance with the ASHRAE 90-75 standards could save over 3 billion kWh of electricity per year in 1990 in the Pacific Northwest. 4/ 12/

c. Installation of appliances or industrial processes to more efficiently transform electricity into a useable service.

It is estimated that improved appliance efficiencies could save about 20.6 percent per house of the electricity used for appliances. This could represent annual average energy savings for the region of 5.4 billion kWh. 2/

Converting to fluorescent lighting while maintaining the same lighting level would save about 33 percent of electricity currently required for residential lighting. This could result in annual average energy savings of 2.9 billion kWh for the region. 2/

Heat pump water heaters, while still developmental, could reduce electricity used for residential and commercial water heating by 50 percent. 16/ This represents regional savings potentials of 11.4 billion kWh annually. 2/

A new heat pump for industrial uses, designed to heat water by removing heat from waste water streams, is commercially available but insufficient data is available to estimate its potential contribution to energy savings.

Process efficiency improvements also offer potential for savings but there is insufficient data to quantitatively estimate them.

A survey of 150 industrial plants in the region by Rocket Research Company identified 0.4 quadrillion Btu (quads) of energy in waste heat. About 52 percent or 60.9 billion kWh of this is considered recoverable for use in adjacent communities to displace other energy forms. 13/

Heat recovery systems for large refrigeration loads such as those of grocery stores are available for space and water heating. However, the regional costs and potential savings of this system are not available. If chillers are installed with waste heat recovery systems, they have the potential to save 33 percent of space heating energy and 20 percent of space cooling energy. 5/ Detailed end-use data is required before potential savings from heat recovery systems on refrigeration units can be obtained.

d. Total potential.

A study by Skidmore, Owings & Merrill (SOM) 2/ provides estimates of potential energy savings which might be achieved by implementation of a comprehensive regional energy conservation program. Table IV-16, summarizes the results of the SOM study for 1995.

It is important to note that the total potential energy savings from the conservation actions described on the preceding pages are not additive. Insulating hot water heaters and reducing lighting, for example, may increase requirements for space heating.

Costs

The price that a user must pay for energy is an important factor in the calculation of economic efficiency criteria. Benefit to cost ratios for specific conservation measures are directly proportional to the price that is assumed for energy. Capital recovery periods are also directly affected by the assumed price of energy. In general,

TABLE IV-16

ANNUAL POTENTIAL ENERGY SAVINGS FOR THE PACIFIC NORTHWEST IN 1995

	With Educational Programs (10^6 kWh)	With Incentive Programs (10^6 kWh)	With Mandatory Requirements (10^6 kWh)
	RESIDENTIAL SECTOR		
Existing (built thru 1974)	6,319	8,954	23,437
New	5,961	8,193	18,595
Total	12,280	17,147	42,032
	COMMERCIAL SECTOR		
Existing (built thru 1974)	2,323	3,919	7,510
New	7,315	10,448	12,030
Total	9,638	14,367	19,540
	INDUSTRIAL SECTOR		
Existing (built thru 1974)	4,442	6,189	7,729
New	2,493	3,710	5,464
Total	6,935	9,899	13,193
Total all sectors	28,853	41,413	74,765

Moving from left to right, savings are cumulative and can not be added.

TABLE IV-17

COSTS OF REGIONAL CONSERVATION PROGRAMS*
(1975 dollars)

	With Educational Programs (10^6 \$)	With Incentive Programs (10^6 \$)	With Mandatory Requirements (10^6 \$)
RESIDENTIAL SECTOR			
Existing (built thru 1974)	\$ 56.3	\$ 91	\$285.9
New	\$ 9.8	\$ 17	\$ 90.7
Total	\$ 66.2	\$208	\$405.1
COMMERCIAL SECTOR			
Existing (built thru 1974)	\$ 74.7	\$121.1	\$330.2
New	\$138.2	\$207.9	\$484.4
Total	\$212.9	\$329.0	\$814.6

INDUSTRIAL SECTOR

Industrial sector costs were not available.

* Extracted from a study performed for BPA by Skidmore, Owings & Merrill, "Electric Energy Conservation Study."

adoption of conservation measures is closely related to the rate of payback.

The SOM study 2/ contains many details with regard to various uses and implementation of conservation programs. The cost information on Table IV-17 from that study is out of date, but nonetheless represents the best information available for this region.

Environmental Impacts.

Generally, except for no-cost conservation actions such as adjusting thermostats, conservation actions involve: mining raw material; manufacturing construction materials such as metals, glass, and insulation; fabricating the finished products; transporting to the point of use; and installation. Each step requires varying degrees of energy consumption and labor, depending on the product.

Higher technology devices such as heat pumps and heat recovery devices require more raw material, manufacturing, and fabrication than conservation-related building materials such as insulation, and require more energy in transportation. Installation requires more specialization and the expected life of the equipment is less. These systems all require maintenance and, because of their size, pose more of a disposal problem when their useful lives are over.

The DOE Office of Conservation and Solar Applications prepared an environmental assessment on its "Weatherization Assistance Program for Low-Income Persons," (April 1979) which assumed that up to 750,000 low-income households would ultimately receive weatherization retrofit materials as a result of that program. The assessment concluded:

> "The only probable adverse environmental impacts which cannot be avoided consist of some near-term increases in air and water pollutants as a result of increased production. However, these increases are short-lived, relatively insignificant, and offset by pollutant reductions from fuel savings. Industries supplying weatherization materials will absorb the demand generated by the program without significant impact. There will be no population and growth impacts resulting from the program action. Employment will not significantly increase in the related industries as a result of the program. However, the expanded program should provide modest employment gains, especially for laborers who might otherwise be unemployed, since manual labor is necessary to install the weatherization materials." 14/

Generally speaking, most conservation programs demonstrate the contention of other studies that "in the broadest sense, the less energy we use the less severe the environmental problems." 15/ By reducing the need for electricity generated by present technologies, conservation minimizes their environmental degradation.

Footnotes

1/ Northwest Energy Policy Project (NEPP), Study Module 1-A, Final Report, Volume I: Summary Report, pages 20 and 21

2/ Bonneville Power Administration Electric Energy Conservation Study; Skidmore, Owings & Merrill (SOM), pp. 73, 96, 121, 186

3/ NEPP, p. 36

4/ Portland Energy Conservation Project, Commercial Conservation Choices, Volume 3C, June 1977, p. 17

5/ SOM, p. 134

6/ NEPP, pg 34

7/ NEPP, pg 43

8/ NEPP, Study Module I A, Final Report, Volume II: Detailed Report of Analysis, p. 244

9/ NEPP, Volume II, p. 243

10/ NEPP, p. 24

11/ NEPP, p. 27

12/ NEPP, p. 36

13/ Pacific Northwest Regional Commission, Industrial Waste Heat for Adjacent Communities and Industrial Applications, prepared by Rocket Research Corporation, December 22, 1978

14/ BPA Memorandum to John Palensky from Walt Pollock, July 20, 1979, Subject: Environmental Determination for Residential Weatherization Pilot Program

15/ Federal Power Commission, 1974, p. 155

16/ Regional Analysis of Residential Water Heating Options: Energy Use and Economics, ORNL/CON-31, Oak Ridge National Laboratory, pp. 6-9

(2) Load Management.

Technology

The basic categories of load management that have been used to encourage off peak hours energy consumption are direct load control, indirect load control, customer energy storage, and utility energy storage.

Direct load control involves the cycling, shedding, or shifting of certain customer appliances or equipment by a utility or by the customer during times of highest system peaks or system emergency. Examples of customer loads considered for direct control are air conditioning, space and water heating, irrigation pumping, industrial loads, and swimming pool pumps and heaters. Load control systems limit the customer's control of loads. The customers manually control the operation of their appliances on direction from the utility, or an automatic device such as a time clock, temperature sensor, or demand limiter controls usage for the utility.

Indirect control involves the use of pricing incentives, principally peak-load pricing.

The use of energy storage devices involves converting electricity into a storable (thermal, mechanical, or chemical) form during off-peak periods for subsequent use in the new form or after reconversion to electricity during peak periods. These devices include: storage space heaters, storage water heaters, "cool" storage for air conditioning, and electrochemical or electromechanical storage for all uses. Utility energy storage is discussed in the sections on compressed air energy storage, batteries, and pumped storage.

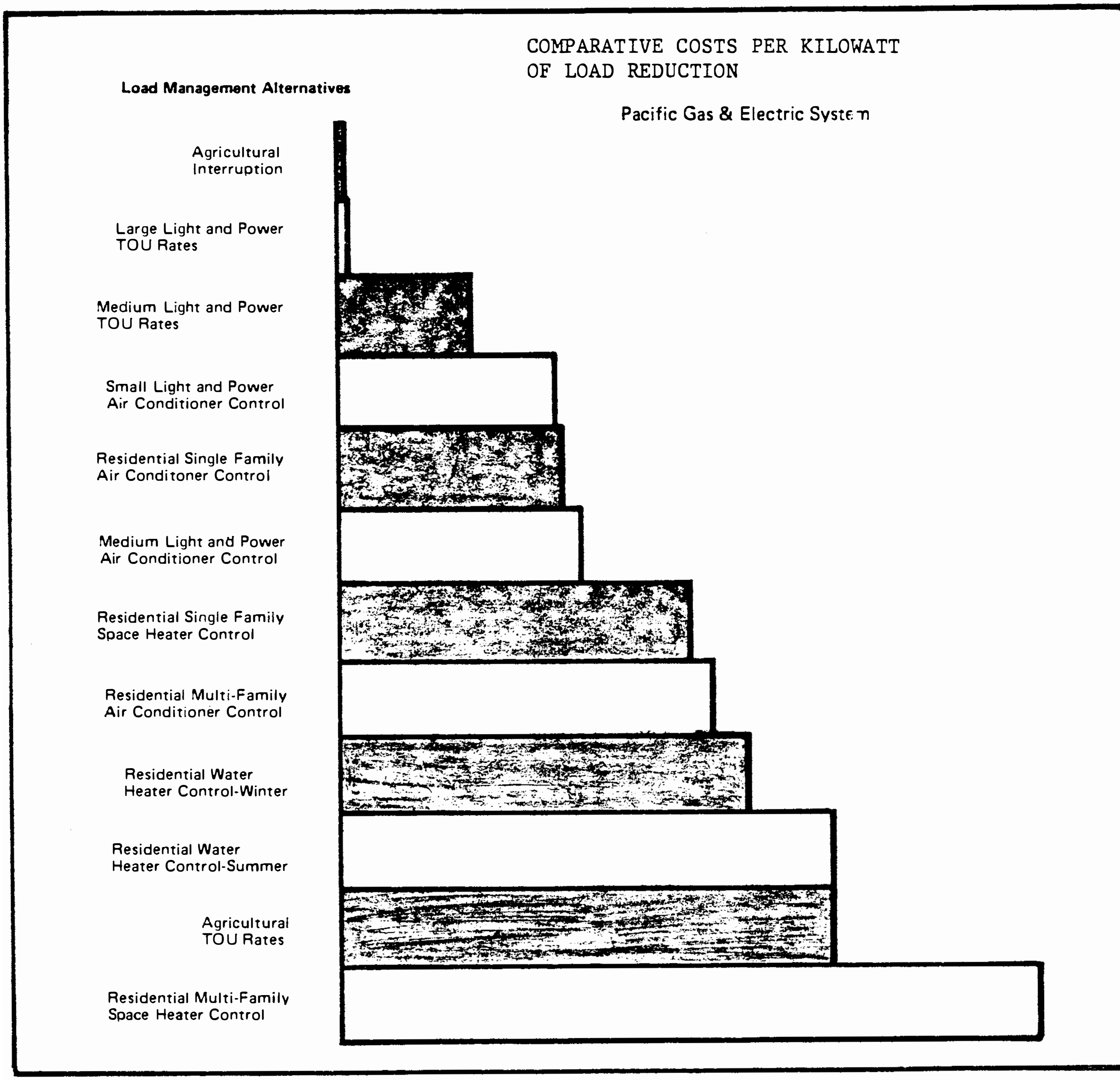
Costs

Control equipment, in general, is still very expensive and could make any system-wide load management program uneconomic. Costs and benefits, therefore, must be carefully analyzed. An evaluation of each potential program must be conducted to determine the impact of load factor changes and reduced revenues over the expected operating life of the proposed program.

Pacific Gas and Electric (PG&E) has investigated the application of various load management alternatives to its system. A comparative cost per kilowatt of load reduction for PG&E's load management alternatives can be found in Figure IV-5.

PG&E has found agricultural interruption quite economical, yet agricultural time-of-day rates have proven the exact opposite. Residential central air conditioning control, at a cost of

FIGURE IV-5



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about $43/kW per single family residence, was also economical to implement. However, the utility found the cost per kilowatt to control water heaters was more than twice as high, averaged over the entire year.

Potential

It is difficult to assess the regional potential of various load management methods. The utility load management experiments that have been conducted throughout the United States have generally had excellent results; however, the operating characteristics of each utility system vary too widely to reach any general conclusions regarding specific benefits for utilities in the Pacific Northwest.

Options may exist in the region for the control of such loads as space heating equipment, cooling equipment, water heaters, commercial lighting, etc. and a hypothetical case can be made for each. For example, based on preliminary end-use studies, there are approximately 2.75 million households in the Northwest. Assuming an electric water heating saturation level of 86.8 percent, 25 percent of those units contributing to the peak system load, and an average 2.5 kW load per unit, this yields a reduction in system peak load of about 596 MW. However, such an analysis looks at the region as a whole and does not consider load factor and cost effects on individual utilities.

With regard to the region's hydro system, load management alternatives could decrease river fluctuations. A flatter load shape would allow more base load thermal power to be utilitized. However, the costs and benefits of this have to be weighed against the cost of the load management program that would be implemented. Some load management techniques may reduce peak loads while increasing total energy consumption. The value of the peak reduction in such cases must be weighted against the cost of the additional energy required.

In order to more thoroughly assess the region's load management potential, further analysis will have to be made with regard to:

a. Individual thermal plant performance and the resulting impact on hourly, daily, and weekly thermal generating capabilities.

b. The capability of a hydro-thermal system to "shape" energy to meet hourly, daily, weekly, and seasonal loads.

c. Marketing strategies and the resulting effects on the system cost and reliability, and the determination of the most economical generating units.

Environmental Impacts

Peaking and load-following requirements of Pacific Northwest utilities are generally met with hydroelectric plants. Because load changes directly affect such requirements, load factor improvements would have a direct effect on the operations of hydroelectric plants. Load management programs would enable the hydro plants to operate at increased load factors and reduced maximum generation levels. Minimum outflows would increase, maximum outflows would decrease, tailwater fluctuations would decrease, and minimum tailwater elevations would increase. Some hydro plants would not be affected by load factor improvements because of extremely tight nonpower constraints dictating specific operations regardless of load.

The reduction of river system fluctuations would be generally beneficial to biological productivity. Water surface fluctuations prevent the establishment of stable biological communities and are generally considered to be detrimental to most forms of aquatic life. In the case of salmon and steelhead, the value of spawning grounds is diminished by water fluctuations associated with peaking operations. Reduction of the fluctuations would improve the spawning grounds. 1/

Hydro pumped storage has similar impacts to other hydro development. Use of load management to reduce peaking deficits would reduce the need for, and impact of, pumped storage development.

Peaking deficits may be met with oil-fired combustion turbines. However, these units have many drawbacks including high operating and maintenance costs, fuel supply, and adverse environmental impacts. Load management would reduce the need to operate these turbines and thus reduce their resultant environmental impacts.

The costs associated with underbuilding or overbuilding capacity would also be reduced because load control methods often have very short construction lead-times compared with normal generating alternatives.

Footnotes

1/ Draft Role EIS, Appendix A - Chapter III

(3) Cogeneration.

Technology

Cogeneration is the simultaneous production of electrical energy and useful thermal energy. The three basic technologies which can be used are shown in Figure IV-6. The steam topping-cycle system consists of a steam generator in which fuel is fired to produce steam which is first used to turn a turbine-generator and then is sent on at an appropriate pressure for process applications. In a bottoming-cycle system, residual heat left after process use is used to generate electricity. A gas turbine cogeneration cycle utilizes a combustion turbine to drive a generator and the exhaust heat from the turbine is used for process applications, either directly or via a steam cycle.

Existing competitive off-the-shelf equipment for the production of electricity and steam is available from one or more manufacturers in flexible arrangements which will satisfy the specific needs of most individual users. Available steam generators for steam topping or steam bottoming-cycles can be fitted to use gas, oil, coal, carbon monoxide, refinery gases, blast furnace gases, wood wastes, red and black liquors, and other fuels. The gas turbine cogenerating systems generally use natural gas, #2 distillate, or naphtha fuels for commercial applications.

New technology is being developed which may be well adapted to cogeneration. Fluidized-bed combustors may contribute to cogeneration both in raising steam for Rankine cycle applications and for producing high-temperature, high-pressure gases from solid fuels suitable for Brayton cycle (gas turbine) applications. Technological advances in low temperature heat recovery may also be adapted to cogeneration. Binary cycles, systems using two working fluids for heat recovery, are being studied both for geothermal applications and industrial waste heat recovery. The development of better thermodynamic fluids and equipment would extend the cogeneration concept to the use of bottoming-cycles utilizing high-temperature process gas flows from aluminum production, petroleum refining, and similar process industries.

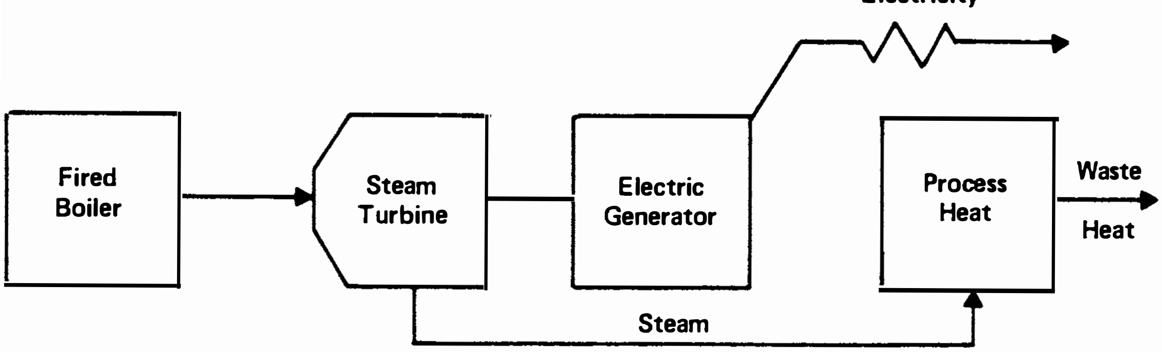
Potential

The compatibility of cogeneration applications with regional industries has been demonstrated historically in the forest-product industries, particularly in the pulp and paper industry. Technical considerations, such as temperature and pressure requirements, do not appear to be obstacles to the development of cogeneration. The seasonal or intermittent nature of the energy supply could, however, raise questions about the compatibility of some cogeneration applications with utility systems. Utility systems usually must provide highly reliable service, and their components, particularly the generating units, must be able to operate when needed to serve demand. The process

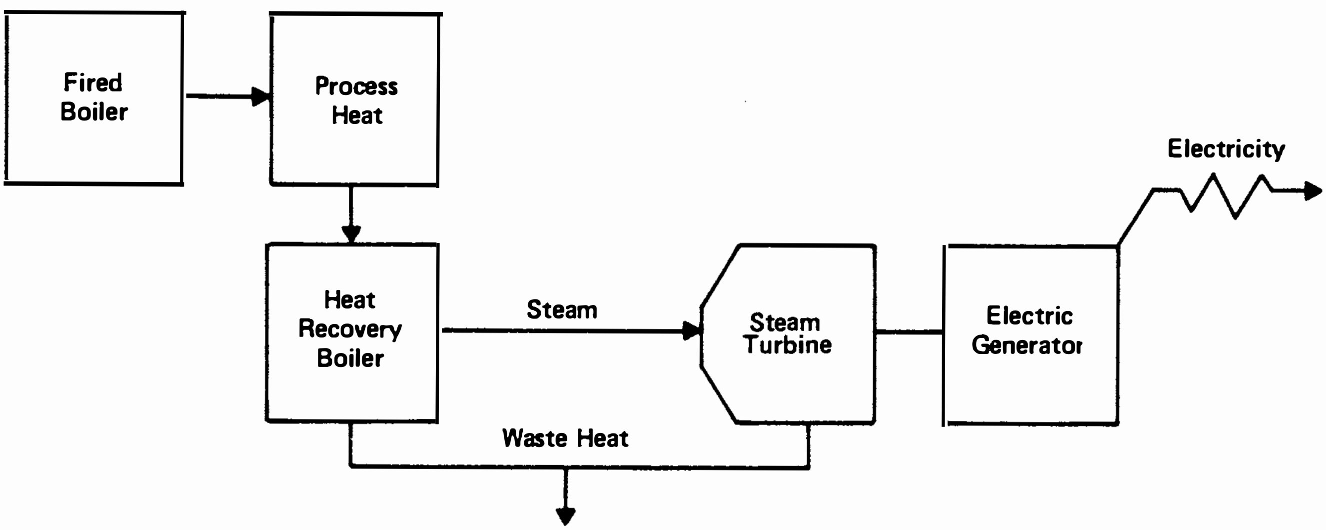
FIGURE IV - 6

BASIC COGENERATION SYSTEMS

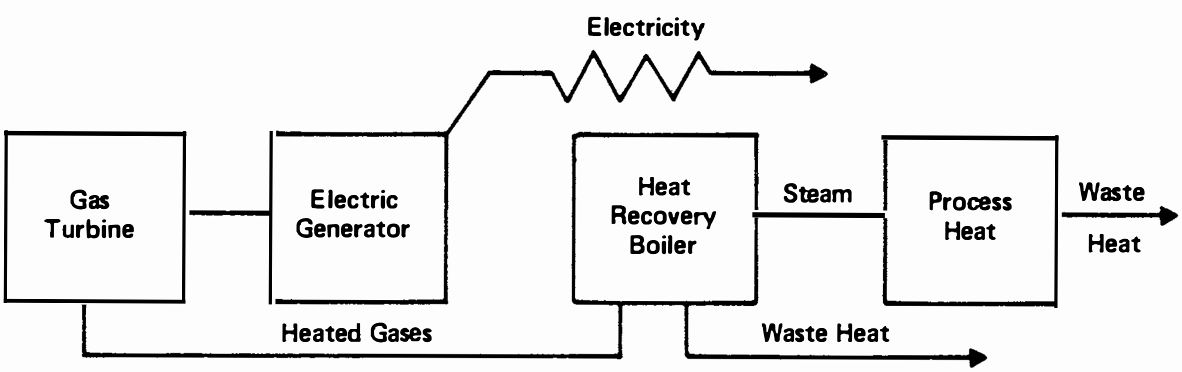
STEAM TOPPING—CYCLE SYSTEM



STEAM BOTTOMING—CYCLE SYSTEM



GAS TURBINE TOPPING—CYCLE SYSTEM



plants operated seasonally use steam and produce electricity only when their products are needed. This characteristic creates a basic technical incompatibility with utility operations. However, in this region, the large storage capability of the Columbia Basin hydro system, and the regional high-voltage transmission grid that interconnects all the utilities could be used to help integrate cogeneration resources. When industrial cogenerators are generating electricity, an equivalent amount of energy can be stored behind the dams as water, unless the reservoirs are full or the hydroelectric system is forced to produce more generation than is needed due to flood control, fisheries, or other nonpower operations.

Many industrial plants consume large quantities of natural gas for low temperature process use, and are good candidates for cogeneration with gas turbines. For example, the Great Western Malting Company plant in Vancouver, Washington, burns natural gas to dry barley malt with 180°F hot air. A gas turbine could be added easily in the system. Other industries which use large quantities of natural gas are petroleum refining, the pulp and paper industry, and food processing.

BPA has conducted a survey, largely under contract, to assess the regional potential for cogeneration. Results of this study are summarized in Table IV-18.

TABLE IV-18

ESTIMATED TECHNICAL COGENERATION POTENTIAL
(megawatts of electricity)

	Identified Through Onsite Visits	Identified Through Statistical Derivation	Total	Already Installed (Included in Totals)	Undeveloped Potential
Washington	423	174	597	204	393
Oregon	224	366	590	163	427
Idaho	172	19	191	33	158
W. Montana	45	--	45	24	21
	871	559	1430 1/	424 2/	1006 1/

1/ Includes 7 MWe not distributed by State.
2/ Installed industrial generating capacity of 29 MWe (condensing) and 4 MWe (hydro) were identified but are not included in the totals.

About 82 percent of this potential is in the forest product industries and much of this potential would be based on renewable wood and wood waste fuels. Note that these are maximum potentials; the amount which could be developed economically and practically is presumed to be substantially less. BPA is continuing its studies to quantify available cogeneration capacity.

Costs

The costs of cogeneration facilities are shared in some fashion by the utility receiving the electrical energy and the industrial firm receiving the heat for process use. Capital costs for a complete, new steam topping cycle cogeneration facilities producing 25 MWe plus 510,000 pounds per hour of steam for process use were estimated as $63-66 million (1979) depending on fuel. In some cases where boiler capacity is adequate, all that may be required is installation of a turbine generator. Capital costs in such a case would be far lower. Capital and energy costs for cogeneration facilities are very much dependent on the particular circumstances, and must be considered on a case-by-case basis. As an example of cost of power from cogeneration, the cost of cogenerated energy sold by Weyerhaeuser to BPA's direct-service industrial customers, including BPA charges for storage, load shaping, and transmission, is 19.5 mills per kWh at the time of this report, not including certain variable costs based on Washington State taxes, oil surcharges, and restart charges. Most cost estimates for cogeneration range between 15 and 30 mills/kWh in 1979 dollars. Contributing to this estimate are studies in 1978, by two wood products companies which produced preliminary estimates of 20 and 25 mills/kWh for projects under consideration. More detailed economic analyses are currently being conducted under several contracts and will be available before the end of 1979.

Environmental Impacts

The environmental impacts of cogeneration facilities are very much the same as the basic technology by which the system derives its energy. For example, the impacts of a coal-fired cogenerating facility are very much the same as a coal-fired generating plant which fires the same amount of fuel. The principal differences are that less waste heat is rejected to the environment and the use of fuel is more efficient than if the electrical generation and industrial process were carried out separately. The reader is referred to the discussions of impacts of coal-fired generation, wood-fired generation, municipal waste-fired generation, and combustion turbines for the impacts of corresponding cogenerating facilities using those technologies.

At the same time, conversion of an industrial facility to cogeneration may have localized impacts. If no preventive actions were taken, industrial cogeneration at an existing plant often would increase air pollution locally. Steam topping-cycle plants (not bottoming-cycle or gas turbine systems) typically burn 10 to 20 percent more fuel, often oil or gas, when cogenerating than when merely producing process steam. Depending on the fuel used and individual plant characteristics, this may increase the emission of particulates, sulfur oxides, carbon monoxide, hydrocarbons, nitrogen oxides, and other pollutants. Existing facilities retrofitted for cogeneration may be required to add air pollution control equipment to handle the additonal stack gases and pollutants, although improved boiler designs and firing techniques can also reduce emissions. A similar effect may occur for water pollutant and water consumption impacts. Although the efficiency of jointly producing electricity and process heat is expected to produce fuel consumption savings on the order of 15-30 percent when compared with separate production, the net reduction in environmental impacts, if any, will occur as a result of the need for fewer central generating plants. The environmental impacts at the industrial plants where cogeneration occurs will often be somewhat greater than from their normal operation.

b. Renewable Resources.

(1) Large Hydroelectric Generation.

Technology

A dam is constructed to create a reservoir and head, or difference in water level. Water flows from the reservoir through turbine blades, which drive the generator, producing electricity, and passes to the downstream side of the dam.

In addition to providing electricity, hydro projects are also used for recreation, irrigation, navigation, residential and industrial water supply, and flood control. However, operating patterns for production of electricity conflict with some of these other uses.

The levels of the reservoirs fluctuate hourly, daily, or seasonally to supply the water needed for electricity production. The water released through the turbines also results in increased fluctuations downstream from the dams.

Potential

The total potential hydroelectric power in the Pacific Northwest is 100,364 MWe, according to National Hydro Power Study data (1980). Total potential energy production in the Pacific Northwest is 320,828 GWh per year. There are 157 hydroelectric plants in operation with 1,877 sites still undeveloped. Economic, environmental, and political constraints will make actual development of many of the potential sites impractical.

The Federal Columbia Power System has units under construction at six sites; four are adding units to existing dams. These six projects have a total additional peaking capability of 1,291 MWe. The contribution of these units to firm energy capability is minor.

Public agencies and investor-owned utilities also propose to add generating capability at new and existing projects. The 1980 PNUCC West Group Forecast (Table 4) indicates addition of 254 MWe at Ross Dam on the Skagit River, of four MWe at Bull Run Dam on Bull Run River, of 38 MWe addition at Mayfield on Cowlitz River and of 11 MWe at Pelton Reregulating Dam on the Deschutes River. Additional generating units under consideration by public agencies and investor-owned utilities at new and existing projects (West Group Forecast, Table 7) 1,847 MWe of additional peaking capability.

Costs

Costs for hydroelectric facilities vary according to the size, type, and location of the dam. Land and relocation of people, buildings, and facilities can be the greatest costs, depending on existing land-uses.

Despite the large capital investments required for hydroelectric development, hydro facilities have offered the most economical source of electric power in the Pacific Northwest. Of the 30 hydroelectric projects on the Federal Columbia River Power Supply System, Grand Coulee had capital costs of less than $100 per kilowatt of nameplate rating capacity; 11 projects cost between $100 and $200 per kilowatt; 13 cost between $200 and $700 per kilowatt; and 3 cost between $700 and $800 per kilowatt.

If costs were the only consideration, the outlook for future hydroelectric development in the Pacific Northwest would be favorable. The average costs of adding the 38 authorized and potential Federal units is estimated to be $600 per kilowatt. Additional units will produce little additional energy, so almost all of the costs must be allocated to capacity. Costs of potential new hydroelectric resources range from $1000 to $1500 per kilowatt of installed capacity.

Environmental Impacts

The environmental impacts of hydroelectric generation are associated with construction of the dam and related facilities, and river operations.

During construction, dust and vehicle emissions will decrease air quality, and erosion, dust and other discharges may contribute to downstream siltation and pollution. Construction may result in significant influxes of workers and associated socioeconomic impacts. An earth-fill dam could require as much as 80 million cubic yards of material, while a concrete dam requires large quantities of steel and cement.

The dams themselves result in impoundments which inundate extensive areas (from 1,000 to 20,000 acres), eliminating wildlife habitat and displacing existing land uses, and have a life expectancy of several hundred years.

The presence and location of the dams affect a number of multiple uses of the river. One of the most controversial issues arises from mortality of fish, especially salmon, and other aquatic life associated with the dams and their reservoirs. Fish ladders have been incorporated to assist adult anadromous fish return to spawning grounds, but, in spite of the ladders, fewer fish are able to complete their migration than prior to construction of the dams. Also, many of the spawning grounds have been destroyed through inundation.

The presence of locks at the dams can enable continued navigation or make possible navigation on stretches of the river where it was formerly impossible. Recreational opportunities are created by the reservoirs. The reservoirs may cover up areas of archeological, historical, or biological significance. For example, riparian habitats and ecosystems are flooded and subject to erosion. The dams also assist the Corps of Engineers in flood control management.

Studies at Columbia River hydroelectric projects indicate juvenile salmon and steelhead suffer mortalities of from 7 percent (Bell, et. al., 1967) to 30 percent (Long, et. al., 1968 and 1975) while passing through turbines. Additionally, water spilling over dams can cause gas supersaturations in the river below which can affect both juvenile and adult fish. Finally, dams tend to disrupt normal migration patterns resulting in passage delays for both juvenile and adult fish. Delays in migration time of anadromous fish results in poor spawning success for adults and low survival for juveniles when moving from freshwater to the saline waters of the ocean.

The hourly, daily, or seasonal operations of the river for power purposes conflict with other uses. Forebay and tailwater fluctuations make some areas unsuitable for recreation or navigation for safety and access reasons, affect the ability to withdraw water for irrigation at some times, and cause erosion of riverbanks. Animal habitats and fish spawning areas can be alternately stranded and flooded. More frequent and rapid fluctuations in generation at the dams, which would result if the hydro system becomes increasingly committed to meeting peak rather than base loads, would exacerbate these adverse impacts.

Footnotes

1/ U.S. Federal Energy Regulatory Commisssion, Hydroelectric Power Resources of the U.S., January 1, 1976.

(2) Small Hydroelectric Generation

Technology

The term "small hydroelectric facility" is generally limited to those facilities with a capacity no greater than 15 MW. Such facilities may entail the development of a new dam or simply add generating capacity at an existing small dam. Little, if any, additional storage capacity would be created at either type of site. Many, but not all, small hydroelectric projects are also low head projects.

The technology used for small hydroelectric projects is comparable to that used for conventional hydroelectric projects. Small hydroelectric projects with a low head can make use of a bulb turbine rather than the Francis or Kaplan turbine used for high-head projects.

Potential

The Hydro Resource Assessment was the subject of a study by the U.S. Army Corps of Engineers. 1/ The Corps surveyed records of sites and projects of at least 50 kilowatt capacity. The results of the study show that in the range 50 kilowatts to 25 megawatts, in Oregon, Washington, and Idaho, there are over 1,000 sites, about 300 of which presently produce power and have a potential for capacity increase of over 1,100 megawatts and additional annual power production of 3,500 gigawatt hours. Another 90 are existing sites with no electric power production which have a potential capacity of over 600 megawatts and annual power production of 3,500 gigawatt hours, and over 700 sites are undeveloped and have a potential capacity of 5,700 megawatts and annual power production of 22,000 gigawatt hours.

The resource assessment work is continuing and is being refined. Potential sites are under further study and some are still being identified. The potential is significant; for example, if all the undeveloped sites could be developed the additional capacity, 5,700 megawatts, would be more than twice that of Grand Coulee. The potential for capacity increase at the sites which currently generate power, 1,100 megawatts, compares with that of a dam like McNary and the potential for power production at dams with no power production, 600 megawatts, is equivalent to the capacity at Bonneville Dam.

Costs

Recent feasibility studies of potential small hydroelectric sites indicate a range in capital costs per installed kilowatt of $1,500 to $2,000 in 1980 dollars unless the existing dam requires little rehabilitation which can reduce the cost substantially. The cost of energy, reflecting current financing conditions and taxes applicable to each project, ranges from 30 to 75 mills per kilowatt hour.

Environmental Impacts

Small hydroelectric projects are licensed and regulated by the Federal Energy Regulatory Commission. Each project must meet environmental standards before being licensed. The impact of a hydroelectric project on the environment can be beneficial as well as detrimental. The main sources of degradation come from the disturbance of silt due to construction activity and changes in water flow which can affect fish, wildlife, and plants. Where there is an existing dam, these changes are likely to be minimal or nonexistent. Beneficial effects can accrue from the restoration of neglected dams, flood control, dam safety improvements, and the creation of recreation facilities.

The materials required for small hydroelectric projects are principally concrete, fill, and steel. Construction impacts are similar to those for large hydroelectric projects but they are of proportionately smaller scale.

The development of projects at new sites may bring about changes in the species composition, degradation of water quality, blockage of upstream and downstream migration, loss of stream and terrestrial habitats and upstream spawning sites through inundation, and increased embolism (i.e., formation of blood clots and gas bubbles in the blood stream) in fish below the dam resulting from gas supersaturation associated with spill. In addition, the development of specific sites may alter or destroy historic structures and archaeological sites, and have an adverse impact on the existing recreational uses of the water and land. Land required for new reservoirs is a site-specific consideration.

Operational impacts include turbine-induced mortality and injuries to juvenile anadromous fish. The extent of the impact due to the turbines depends partly on the type of equipment used. A bulb turbine may result in less impact than a conventional turbine. Recreational use of reservoirs may be impacted as a result of fluctuations in reservoir levels caused by power generating operations.

Footnotes

1/ U.S. Army Corps of Engineers, Institute for Water Resources, National Hydroelectric Power Resources Study; Small-Scale Hydroelectric Power Resources; Energy Brief: Pacific Northwest, Including California. (July 12, 1979), p. 4.

2/ A. Ragnar Engebretsen, "Economic Comparison of Five Hydroelectric Projects in Idaho," in Low-Head Hydro, compiled by John S. Gladwell and Calvin C. Warnick (Moscow, Idaho: Idaho Water Resources Research Institute, 1978), p. 73.

(3) Solar Energy: Central Station Applications.

Technology

At present, two feasible types of terrestrial solar-electrical generation have evolved: solar-thermal, and solar-photovoltaic.

Solar-Thermal. Solar-thermal conversion systems collect incident solar radiation from a large area and concentrate it onto an absorptive receiver. Heat absorbed by the receiver is transferred on a working fluid which drives a thermodynamic engine, using either a Rankine (steam turbine) or Brayton (gas turbine) cycle to generate electricity. Two major approaches to this concept are the central receiver and distributed collector.

The central receiver approach utilizes a field of sun-tracking heliostats deployed around a tower-mounted receiver. The heliostats reflect sunlight onto the receiver which absorbs the sun's energy as heat. This heat is subsequently transported by the working fluid to the thermal-electrical converter. The distributed collector system consists of a series of individual collectors, each collecting and concentrating the solar radiation and converting it to thermal energy. This thermal energy can be transported by a working fluid to a central powerplant for thermal-electrical conversion or, using a small heat engine, converted to electricity at the collector site and transported directly as electricity. Because of the difficulties inherent in collecting energy dispersed over a square mile or more of area, such systems are considered to be less efficient than the central receiver systems.

While not commercially available, a 5-MWe Solar Thermal Test Facility near Albuquerque, New Mexico, has recently been completed. Design has begun on a 10-MWe solar thermal pilot plant, planned for a location near Barstow, California, and scheduled to begin operation in 1981. Distributed receiver systems presently under construction near Fort Hood, Texas, and Shenandoah, Georgia, are to begin testing in late 1980. 1/ In addition, the first 100-MWe commercial-sized demonstration plant is being planned with an on-line date of 1985.

Available information suggests that solar thermal conversion systems may range in size from one-MWe to several hundred MWe in capacity. Because of the intermittent nature of sunlight, energy storage facilities are generally incorporated into plant designs to increase the plant's capacity factor. Capacity factors of 45 percent can be achieved utilizing 6 to 12 hours storage capability in solar thermal plants.

Solar-thermal conversion systems with average operating temperatures greater than 1,000°F have thermodynamic conversion efficiencies of 38-48 percent. 2/

Solar Photovoltaic. Solar photovoltaic cells, or solar cells, are attractive in that they convert incident sunlight, both direct and diffuse, directly into direct current electricity. Several materials exhibit photovoltaic behavior, although the single-crystal silicon cell has become the industry standard.

Photovoltaic cells are currently available as "shelf items."

There is no information regarding optimum unit sizes of photovoltaic systems or on capacity factors for photovoltaic systems. Technological advances in storage systems will increase capacity factors. Photovoltaic arrays utilizing commercially manufactured silicon cells typically achieve 6 to 8 percent efficiency with individual cell efficiencies ranging from 12 to 14 percent, 3/ although some developmental cells reach 16 to 18 percent efficiency. 4/ Their output is dependent on the intensity of light striking them. Therefore, output is reduced on cloudy days and is nothing at night. A storage system or additional generation is needed to back-up a photovoltaic plant to meet loads when light conditions are adverse.

Potential

The Council on Environmental Quality predicts that with appropriate incentives, solar technologies could contribute up from 5 percent to 25 percent of national energy needs by the year 2000. 5/

Parts of the Pacific Northwest annually receive 70 to 80 percent as much solar radiation as the arid and semi-arid areas of Southwestern United States. This translates to an average of 4.5 kWh of incident solar energy per square meter per day. 6/ Because the current maximum conversion efficiency is approximately 10 percent, about .4 kWh can be generated per square meter per day. 7/ Preliminary assessments by the University of Oregon estimate a maximum generating capacity ranging from 67 to 100 GWe, if an area of approximately 1200 square miles in Southeastern Oregon alone were dedicated to solar conversion. 8/ However, this technical potential can never be fully achieved due to environmental, political, and cost restraints.

Costs

A considerable amount of effort is being directed at the development of cost and performance data for solar electrical generation technologies. Because plant designs have not been finalized and the technology is continually advancing, the data for solar electrical plants are subject to continual revision.

Due to the high cost of manufacturing photovoltaic cells, a utility-sized generation facility, using state-of-the-art cells, would be prohibitive in cost. While it is anticipated that costs for solar cells will drop, widespread utility service does not necessarily follow. Commercial utility use depends upon technological advances in energy storage facilities in addition to the relative costs of conventional energy sources.

Solar Thermal. Capital costs at 1975 price levels are estimated to range from $1,100 to $2,200 per kW. Bus bar costs are estimated at 60 to 115 mills/kWh. These estimates assume a 45 percent capacity factor. 9/

Solar Photovoltaic. Capital costs at 1975 price levels are estimated to range from $2,500 to $5,000 per kW. Bus bar costs are estimated at 60 to 120 mills/kWh. These estimates assume a capacity factor of 20 to 25 percent. 10/

Environmental Impacts

Significant development of central solar powerplants will require substantial quantities of steel, aluminum, concrete, glass, copper, silicon, and other materials. Production of these materials will increase the environmental impacts of these industries. 11/ Facilities for fabrication of solar generation components, such as heliostats, and additional production facilities for solar cells will be required. Production of some types of solar cells involves hazardous materials such as cadmium and arsenic.

Construction impacts of central solar facilities will be the emission of pollutants from construction vehicles, dust stirred up by construction operations and wind erosion of exposed soil, and noise. Plants and some animals will be killed during the clearing of the site, and mobile species of animals will emigrate off the site. The major impact to central solar plants is the commitment of large land areas. Photovoltaic plants require 2.1 to 4.5 square miles per GWe of capacity, depending on the type of cell, and 20 to 30 square miles per GWe of capacity are required for solar-thermal central receiver plants. 11/

Many of the environmental effects associated with operating photovoltaic and solar thermal central receiver plants will be similar. The presence of large numbers of heliostats or photovoltaic arrays will modify local terrain, species composition, and microclimate. Wind and water erosion will increase due to disruption of soil surfaces and vegetation removal. Shading from photovoltaic arrays and heliostats may induce changes in local plant communities by decreasing temperature and moisture evaporation rates, resulting in a rise in the local water table. Both systems may adversely affect wildlife species by interfering with grazing patterns. 11/

Photovoltaic plants will emit no gaseous or particulate pollutants, liquid wastes or solid wastes (except under atypical conditions such as release of toxic compounds during a fire). Although the plant releases no thermal pollutants *per se*, large arrays of cells may function as "heat islands" via reflection of sunlight.

This effect is anticipated to be minimal since maximum sunlight collection (and thus, minimal reflection) is strived for in array designs. Silicon and CdS photovoltaic plants will require only negligible amounts of water for panel cleaning. Thus, there is little potential for polluting local water systems. Although, optically concentrating systems will require water to cool panel frames supporting the cells, system designs presently utilize a recirculation process, thereby minimizing water input requirements and releases. 11/

Solar thermal central receiver systems emit no particulates, sulfur dioxide, or nitrogen oxides. However, all systems require a working fluid and a cooling loop. In addition, many designs incorporate an energy storage subsystem often comprised of eutectic salt or heat transfer oils toxic to wildlife. Leakage of working fluids or storage media may adversely affect local water quality. Cooling loops can utilize either wet or dry cooling towers. Drift from wet cooling towers will affect local air quality since it will contain chemicals, such as algicides and anticorrosive compounds. Heliostat glare could affect bird navigation and the concentration of energy near the receiver may burn flying species passing too close. 11/

Decommissioning central solar plants will result in impacts similar to their construction. Potential environmental problems posed are the safe disposal of some types of photovoltaic cells containing hazardous materials (cadmium and arsenic) and toxic eutectic salts and heat transfer oils. 11/

Footnotes

1/ Status Report on Solar Energy - Domestic Policy Review, August 25, 1978, p. III-5.

2/ Pollard, W. G., "A General Method for the Evaluation of Possible Systems for Electric Generation With Solar Energy." IEEE Transactions on Power Apparatus and Systems, Vol. PAS-97, No. 5, Sept/Oct. 1978, p. 1657.

3/ Laliberte, Margaret, "The Sun on a Semiconductual." EPRI Journal, March 1978, p. 21.

4/ See Footnote 2.

5/ Council on Environmental Quality, Solar Energy, Progress and Promise, April 1978.

6/ Caputo, R. S. and Truscello, V. C. "Solar Thermal Electric Power Plants: Their Performance Characteristics and Total Social Costs." Presented at the Eleventh Intersociety Energy Conversion Engineering Conference, Stateline, Nevada, September 1976, p. 114.

7/ Ibid.

8/ McDaniels, D. K., et. al., "Solar Electric," Oregon Solar Planning Study, submitted by University of Oregon and Oregon State University to the U.S. DOE and the Oregon DOE.

9/ Draft Role EIS, p. V-218.

10/ Ibid.

11/ Lawrence, Kathryn A. A Review of the Environmental Effects and Benefits of Selected Solar Energy Technologies (Golden, Colorado: Solar Energy Research Institute), p. 4.

(4) Solar Energy: Direct Use Applications.

Technology

Direct-use solar technologies include heating and cooling of buildings, water heating, and process heat for industrial and agricultural applications. Solar cooling systems are not expected to make much contribution in the Pacific Northwest in the near future because of the moderate climate.

Solar systems collect sunlight and transfer the radiant energy by means of liquid or air to a storage system. The storage may be in the form of water, rock, eutectic salts, or elements of the building itself; the stored heat may be in sensible or latent form. Solar systems may be "active" or "passive." Active systems rely on an additional energy source to transfer thermal energy; passive systems rely on building orientation, landscaping, structural design, use of materials, etc., to allow for maximum solar collection and movement of heat by natural, nonmechanical means. Solar heating and cooling systems can be used in either large applications (commercial/industrial buildings) or small (residential).

Solar water heating systems are generally active, with the exception of the passive thermosiphon system which does not depend on electric power to pump the heat transfer fluid through the solar collector array. Solar water heating systems generally include pre-heating water tank(s) to supplement the existing water storage tank(s).

Solar process heat can be used in industry and agriculture, such as in food processing, lumber drying, and crop drying. The solar system collects the sun's radiant heat, converts it to sensible heat in a working medium (air, water, or steam), distributes the heat to a process application, and stores excess heat energy. A variety of planar or concentrating collectors may be used in the solar systems, as well as a variety of storage devices, depending on the temperature needs of the process. Temperatures that can be achieved for solar process heat range from 40°C to 150°C, though most high-temperature solar heating systems are conceptual designs or prototypes and system performance has not been proven. Low-temperature systems (less than 100°C) are being manufactured currently, and their performance is well documented.

Potential

Several factors need to be evaluated in order to assess the regional potential for solar heating and cooling of buildings, water heating, and process heat; namely, (1) available insolation; and (2) year 2000. 1/

Costs

Solar collection systems for active space heating and cooling systems and water heating vary from $15 to $30 per square foot (installed cost), depending on a variety of factors including system type, manufacturer, size, and complexity of installation. A solar collection system costing $15 per square foot and producing 200,000 Btu per square foot per year is estimated to have an energy cost of $7.50 per million Btu. 2/

Passive techniques typically add little to the cost of a new building, but generally cannot be added to existing buildings except at considerable cost, because they tend to be inherent in the building orientation, structural design, and choice of building materials. A low-cost greenhouse is an exception.

Solar process heat applications involve initial costs of from $18 per square foot of collector area to $73 per square foot, 3/ depending on the temperature required for the process and the type of system suited for that process.

Solar energy compares favorably with other sources of energy when life-cycle costing is analyzed. 1/

Environmental Impacts

". . . solar energy technologies can be expected to have far fewer and far smaller detrimental effects than conventional sources . . . ." 4/ The use of solar energy reduces the need for transmission lines or the mining, harvesting, or processing of fuel.

Resource requirements for collectors include glass, copper, and aluminum, which are energy-intensive to produce and have detrimental environmental effects on air and water quality in their production.

Potential impacts to public health and safety could result from water contamination, glass breakage, and collector overheating causing fire. These could be mitigated by proper design, installation, and maintenance of systems.

Socioeconomic impacts of solar energy on the economy and employment are beneficial. Studies indicate that widespread use of solar space and water heating systems can provide jobs for welders and plumbers, sheet-metal workers, carpenters, engineers, and architects. Where the solar market is well developed, such as in California, these impacts have been documented. 5/

Footnotes

1/ Solar Energy, Progress and Promise, Council on Environmental Quality, April 1978.

2/ Potential Contribution of Solar Energy in the Northwest, paper for presentation at the Thermal Power Conference at Washington State University by Kirk Drumheller of Battelle Pacific Northwest Laboratory, November 1978, with changes made in April 1979.

3/ Economic Feasibility and Market Readiness of Solar Technologies, SERI, September 1978.

4/ Solar Energy, Progress, and Promise, op. cit.

5/ Ibid.

(5) Large Scale Wind Power.

Technology 1/

The generating capacity of a wind turbine depends upon air density, wind speed, and the area swept by the turbine blades. The amount of energy contained within the wind is proportional to the cube of the wind speed. Therefore, a slight change in wind speed creates a significant change in energy generation, provided the changes are within the operating range designed for the particular wind machine. Wind turbines must take advantage of this relationship of wind speed to the energy available from the wind. Once the wind has increased to the threshold value for initial generation, electrical output will increase as the wind increases until the speed has approximately doubled, at which time the maximum generation (capacity) of the machine will be reached.

Wind power technology has developed around the design standards of horizontal-axis and vertical-axis wind turbine generators. Each design has distinct advantages relating to initial cost and maximum electrical generation. While the method of extracting wind energy differs between vertical and horizontal axis machines, both need a steady airflow to maintain constant power generation, although the wind is rarely steady.

Using present technology, it has been estimated that a horizontal-axis wind turbine with a blade span of 200 feet and peak generation capability of 1.25 to 2.50 MWe would produce the most economical wind generator.

The location of wind turbines is of paramount importance to insure optimum generation from each facility. A profile of seasonal and annual wind characteristics must be developed for each potential wind generation site. The wind patterns of a given site are affected by the terrain and have variable seasonal characteristics. Evaluation of these factors becomes very important when selecting between alternative sites for a wind turbine facility.

A potentially good site for a wind power facility has mean wind speeds of 12 to 15 knots during the year, with relatively little vairance compared to an alternative site. The site should also be relatively close to existing transmission facilities.

A problem associated with the use of wind power arises because of the intermittent character of the wind which leads to an unreliable power supply in the short term. This shortcoming must be compensated for by providing a back up source of generation such as hydro or oil or gas-fired power peaking facilities. The peaking plants, which generally have high operating costs, can pick up load rapidly to fill in when winds are slack. Since mean wind speeds have relatively small variance when averaged over a one or 2-year period, wind energy can be considered as a firm resource if storage is available. A storage capability exists in the reservoirs of the Columbia River Power System which makes this system particularly suited to accept and make optimum use of wind energy.

Potential

The wind energy resource for a given region is defined by: (1) the power density of the wind; (2) the available land area; (3) the characteristics of the wind turbine; and (4) the spacing between individual wind turbines. The first two elements introduce a large amount of uncertainty when attempting to assess the energy potential on a regional basis.

Annual average wind power density has been estimated from existing climatological data. 2/ 3/ However, this type of estimate has the inherent disadvantage of utilizing a data base which was not intended for assesments of wind power. Estimates of land available for wind generating stations are limited by the generic character of the estimates which fail to take into consideration all site-specific characteristics which may preclude use as a wind site. Although wind turbine characteristics can be specified with relative confidence, the appropriate spacing between turbines is subject to much speculation. The primary reason for problems with the spacing of machines in an array results from a lack of operational data regarding turbulence in the wake of a given machine as well as lateral interference. Machine spacing has the most significant influence on calculations of available wind energy for a wind "farm" facility. 4/

The question of maximum potential wind energy for a particular region, therefore, becomes academic due to the lack of basic data. However, based on limited site data, a Pacific Northwest wind generator network with a capacity on the order of 2,500 megawatts has been postulated. 5/ Although this study did not identify either the minimum or maximum potential for the region, it does provide an example of the potential from a particular network of wind generators.

In terms of energy, the network postulated above would yield about 8,290,000 MWh per year.

Costs 6/

A report concerning the economic aspects of wind power generation was prepared and submitted under contract to BPA by the Stanford Research Institute (SRI). The model for this report is a horizontal axis wind turbine, having a peak generation capability of 1.5 MWe. For this analysis, it was assumed the wind turbine system would be in mass production for commercial application by the mid-1980's. This assumption is supported by present trends in wind power technology, developed from initial full scale experimentation in the field. All capital cost components for this study were based upon 1975 price level values. The estimate of capital cost investment in 1985, for the wind turbine system described above, is $500 per peak kilowatt. Technical innovations are expected to reduce this value by $50 per peak kilowatt by the year 1995. This compares with a capital cost of $1,000 to $2,000 per peak kilowatt for the relatively small, experimental wind power units operable in 1975.

Due to the sporadic nature of wind power generation, the system under examination by the SRI report was assumed to produce 40 percent of its maximum possible electrical output over the period of a year. Given this annual production capability, the cost of energy which will recover investment expenses and annual operation and maintenance charges was estimated to be 20 to 30 mills/kWh. The exact cost of energy will depend heavily upon ownership, which determines taxation and the interest rate for funds borrowed for project construction.

An important factor to consider when comparing the cost of wind-generated energy to the costs associated with conventional generating sources is the dependability of power production. The cost of energy from conventional nuclear or coal-fired stations represents firm energy, which is available upon demand. Wind-generated power is intermittent and availability depends upon fluctuating wind patterns. Therefore, to compare the cost of energy generated by these resources, the ability to serve electrical loads upon demand and for any given length of time must be taken into consideration.

The estimates outlined above would be valid for a single station. However, grouping several wind turbines together to form a wind farm would create significant costs over and above the price of installing each wind turbine unit. These costs arise primarily from the purchase of large tracts of land to provide spacing between units.

Environmental Impacts 7/

A wind farm system with a maximum generating capacity comparable to the Trojan nuclear powerplant (1,130 MWe) would encompass approximately 45 square miles and contain 500 to 1,000 separate wind generation units. The exact number of units and the area covered will depend upon the generating capacity of each unit and the allowable spacing between units. Purchase of land would be limited to about 5 percent of the total area covered (for access roads, transmission easements, and wind generator sites); land between units could continue to be used for grazing or other nonintensive agricultural purposes.

Wind turbines will be mass produced in a factory and transported to the sites where they are to be erected. Manufacture of wind turbines will result in impacts typical of manufacturing plants, but these have not been quantified. The erection of a wind turbine and tower assembly would adversely affect the esthetics of the surrounding area, in some people's opinion. Construction of a roadway for installation, operation, and maintenance of a wind turbine facility, in combination with the construction of a transmission system for removing the generated power, would create an impact on plant life and animal habitats on and adjacent to the location of the wind turbine. These impacts would be magnified in the case of a wind farm, where a larger quantity of land would be affected, although only 5 percent of the total land involved would be directly affected. In some cases, there would be an impact on local agricultural processes. Also, the erection of a tower would create an obstruction to low-flying aircraft and could interfere with television and radio transmission. The towers might also cause bird kills, but experience so far with existing demonstration units has not shown this to be significant. Wind power does not involve combustion or produce a byproduct during the generation of electricity, hence it is generally free of pollution. Noise generated by the rotating blades of a single wind turbine would be insignificant. The intensity of noise would be similar to that produced by the wind blowing through a stand of trees. Another possible impact from the large scale application of wind farm systems would be the disruption of wind patterns with resultant changes in the details of the microclimate of areas adjacent to the wind farm site. Decommissioning a wind turbine poses no particular technical or environmental problems.

Footnotes

1/ Draft Role EIS, pp. V-145 to V-158.

2/ Energy Research and Development Administration, Wind Energy Mission Analysis - SAN 1075-1/1 (Burbank, California: Lockheed California Company, September 1976).

3/ Energy Research and Development Administration, Wind Energy Mission Analysis, COO/2578-1/2 (Philadelphia, Pennsylvannia: General Electric Company, February 18, 1977).

4/ Ibid, p. 3-42.

5/ Bonneville Power Administration, Network Wind Power Over the Pacific Northwest, Report No. BPA 77-2, BPA Supplement (Portland, Oregon: BPA, January 1978), p. 3.

6/ Draft Role EIS, pp. V-156.

7/ Draft Role EIS, pp. V-157.

(6) Small Wind Energy Conversion Systems (SWECS).

Technology

SWECS, as defined by U.S. DOE, are machines of 100 kW or less. Currently, however, most commercially available machines are 3 kW or less. 1/ SWECS consist simply of a blade assembly mounted on a shaft which is turned by the wind to drive a generator. Because the wind cannot generally be depended on to always blow at the times power is desired, batteries may be used to store the energy for use as needed. In order to interface with a utility and/or to operate some electrical devices, it is necessary to use an inverter to convert the power to 60-cycle alternating current.

Most SWECS manufactured today have low-voltage d.c. (direct current) generators designed for battery storage. Battery storage systems are best used, and may now be cost-effective in remote areas where commercial electricity is not available or where the cost of building a transmission line is prohibitive. They are not economical where commercial electricity is available.

The synchronous inverters required to interface SWECS with a d.c. output to a utility grid present some potential problems to utilities. They may feed electrical noise into a limited number of homes, the utility grid, or telephone lines. They also have very low power factors. However, these problems can be solved.

Several manufacturers have developed SWECS with a 120-240-volt induction generator synchronized to the utility grid that eliminates these problems, especially in sizes of 10 kW or larger. Currently only one commercially available machine uses this technology in the 1-4 kW range, the size range used for many residences.

SWECS towers should be at least 30 feet higher than any building or other obstruction within 300 feet. Since they must generally be fairly close to the point where the energy is being used in order to keep line losses acceptably low, tower height will generally be at least 60 feet. The Residential Conservation Service Program of the National Energy Act requires that wind systems be located at least one and one-half tower heights from any occupied structure or property line. These requirements and code height restrictions generally limit SWECS installations to nonurban or rural areas.

Most future development effort is likely to be aimed at SWECS producing electricity instead of mechanical power since electricity is the more versatile form of energy and represents by far the largest market. Thermal output systems are being investigated but their economic feasibility is unknown.

Potential

There is currently no good regional assessment of realistically available and developable SWECS capacity. The Wind Power Study prepared by Oregon State University 2/ or the soon to be completed regional assessment being performed for DOE by the Pacific Northwest Laboratories may aid in estimating regional potential.

Cost

The total installed costs for SWECS of 2 to 4 kW integrated with the utility system range from $6,000 to $15,000. A battery storage system and a free-running inverter would add about $4,000 to $6,000.

Annual operation and maintenance costs are currently estimated at about 1 percent of the installed cost and amortization will depend on the method and terms of financing. Harsh SWECS environments such as salt air or turbulence caused by installation too close to abrupt topographical features will reduce the expected 20 to 30-year life to 15 years or less, significantly increasing costs in these cases.

Current estimates of SWECS energy costs range from about 30 to 200 mills per kWh. The median energy cost of currently marketed small wind turbines is 154 mills per kWh assuming an average annual wind speed of 12 miles per hour, 12 percent interest, 1 percent O&M costs, a synchronous inverter, a 15 year life, an owner in the 25 percent tax bracket, and no incentives. 3/ SWECS energy costs are most sensitive to annual wind speed, followed by interest rates. DOE energy cost estimates for currently available SWECS range from about 110 to 240 mills per kWh. 4/ The DOE goals are to reduce SWECS energy costs to about 40 to 60 mills per kWh and to improve reliability.

Environmental Impacts

SWECS are manufactured in plants and shipped to the site where they are to be installed. Impacts of manufacturing SWECS are typical of those for manufacturing operations. No particular environmental problems are known to result from SWECS manufacture. Installing SWECS results in impacts typical of construction but on a very small scale.

"SWECS have no significant environmental impacts, although environmental questions are still under study. It should be noted that zoning ordinances will restrict SWECS to nonurban areas; primarily only rural and agricultural areas are being considered. Consequently, SWECS environmental impacts will generally be experienced only by the user." 5/ These impacts include:

Audible noise: Smaller SWECS can produce limited audible noise, but with carefully designed systems, it is unlikely to significantly deter the owner or extend beyond the owner's property.

Esthetics: Careful site selection and design aids can reduce impacts when they occur. (However, esthetics have caused the largest number of lawsuits nationwide for solar systems and solar is relatively innocuous esthetically when compared to wind systems).

Television interference: Television interference problems (for the wind generator rotor only, excluding synchronous inverters and other equipment that can feed electrical interference back into the power grid) are functions of machine size. In most installations, the small systems should not encounter this problem, especially those with wooden blades. Mitigation could usually be achieved by moving the wind turbine, or by use of directional TV antennas.

Ecological effects: Bird strikes, microclimate modification, small animal habitat change, and the other remaining environmental impacts are generally innocuous.

Safety: Some potential safety problems can be encountered. Towers can fall and the machines can throw rotor blades. The likelihood of these events happening is small, since towers are designed to withstand the highest wind speed most likely to occur. Potential damage can be reduced by placing the wind turbines at least one and one half tower lengths from occupied buildings and property lines.

Wind turbines and their towers can be classified as an attractive nuisance, which makes the owner liable for injuries from people climbing on the tower, even if they were trespassing to reach the tower. This danger can be minimized by fencing around the tower.

Footnotes

1/ A Guide to Commercially Available Wind Machines, RFP 2836/3533/78/3, by the U.S. Department of Energy, April 1978, pp. 1 and 27-30.

2/ "Wind Power-Network Wind Power Over the Pacific Northwest," BPA 77-2, Oregon State University.

3/ Commercialization Strategy Report for Small Wind Systems, TID 28844, by U.S. DOE Task Force chaired by Louis V. Divone, January 1979, p. 4.

4/ Ibid. p. 5.

5/ Ibid. p. 3.

(7) Wood-Fired Electrical Generation

The technology of using wood to produce electrical energy in centralized generating facilities is well developed. Wood-fuel (whether from trees harvested solely for energy purposes, residue left after other forestry operations, waste from forest products plants, or from some combination of these) is collected, transported to the site of the generating plant, and burned in a boiler of specialized design. Depending on the initial condition of the fuel, it may be hogged or chipped at some point prior to firing.

Steam is produced in the boiler which drives a turbine-generator, producing electricity in the same manner as in a conventional coal or nuclear plant. Some means of condensing the steam and rejecting waste heat, such as a cooling tower or ponds, must be provided. Cooling tower and boiler blowdown requires treatment and/or disposal as in other steam-based generating cycles.

The majority of the particulate matter in the combustion gases is removed prior to discharge with mechanical collectors (cyclones), a scrubber (requiring additional water treatment and disposal), a baghouse, an electrostatic precipitator, or some combination of these. The fly ash constitutes a solid waste requiring handling and disposal. Wood or wood-waste can also be co fired with other nonconventional fuels or fossil fuels.

Potential

Wood is a renewable resource as long as provisions are made for its regeneration. The potential of wood for use in energy production in the Northwest is believed significant. BPA is currently studying this potential since it has not been well quantified on a regionwide basis. The Northwest Energy Policy Project estimated collectable forest residues and mill residues in Washington, Oregon, and Idaho, on an energy basis, as being 254×10^{12} Btu/year, 1/ which could represent as much as $17,860 \times 10^{3}$ MWh. The principal constraints on utilization of wood and wood waste as an electrical energy resource are: (1) the cost of collecting the material and transporting it to a common site where the conversion to electrical energy can occur; (2) the competition for this material with other uses; and (3) the necessity to secure assurance of a long-term fuel supply. Wood could be grown and harvested on plantations solely for energy purposes to increase its supply if desired, but this would require commitment of large land areas, water resources, and scarce fertilizer materials.

Cost

In a joint study, BPA and the U.S. Forest Service assessed the cost of a hypothetical 25 MWe generating plant fired with forest logging residue and located in the vicinity of Estacada, Oregon. 2/ Capital costs were estimated as $28.3 million in 1982 dollars plus $5 million for a fuel processing plant and storage yard. Bus bar energy costs were estimated as 50 mills per kWh (1982 dollars) for a plant coming on line in 1982. For a plant coming on line in 1990, energy costs increase to 76 mills per kWh (in 1982 dollars) because of inflation and escalation.

The bus bar energy costs are highly dependent on the costs of collecting and transporting fuel which in turn are dependent on the size and characteristics of the fuel supply area and its proximity to the plant. Mill residues are generally a lower cost fuel than logging residues because the transportation costs are sunk in the operating costs of the mill.

Environmental Impacts

A Department of Energy (DOE) draft environmental impact statement 3/ addresses a proposed wood-fired cogenerating facility at Westbrook, Maine. The proposed plant is designed to fire approximately 2,000 tons of mill residues and harvested chips containing 50 percent moisture, plus 1,440 gallons of 2.1 percent sulfur, No. 6 oil per day. The plant would be equipped with additional oil burners to fire up to 89,280 gallons of 0.7 percent sulfur oil per day under emergency conditions if the wood fuel supply became disrupted. Daily heat input under normal conditions would be 16.8×10^9 Btu from wood and 0.3×10^9 Btu from oil, and the plant would produce about 25 MWe of electrical power plus about 480,000 pounds per hour of process steam. If the plant were only to generate electricity instead of cogenerating, it could produce about 50 MWe, and it would discharge greater amounts of waste heat.

Information in the draft EIS for the Maine facility was used for estimating impacts of wood-fired generating facilities which might be constructed in the BPA service area.

Construction. Construction would not be expected to cause significant adverse environmental impacts except for traffic congestion and noise. At the peak of construction activity, as many as 550 vehicles transporting workers could arrive daily at the site. Sound levels would be raised by as much as 13 decibels in nearby areas, which would be objectinable to most people.

Construction of a facility comparable to the proposed Maine wood-fired powerplant would create approximately 510 direct jobs for the duration of the 2-year construction period. Direct income accruing from plant construction would total \$15.7 million annually and secondary income effects would add to the income of the local area.

Harvesting and Collection. The environmental impacts of harvesting or residue collection are highly management dependent. Properly conducted, harvesting and residue collection should have few impacts. However, some such operations do significantly affect the forest environment. Soil compaction, erosion, and changes in organic matter content can occur if the operation is poorly managed. Soil compaction is normally a temporary condition and not serious. The most severe erosion incidents typically occur as a result of inadequate use of erosion control techniques in the design of forest roads. Erosion results in the loss of critical topsoil, causes gullying, and may reduce the long-term productivity of the forest.

Soil erosion almost inevitably increases sediment loads in streams or ponds. Other impacts on water quality occur as a result of increased nutrient leaching and the removal of trees which shade streams. Both increased nutrient leaching and water temperature may accelerate rates of eutrophication of harvest region water.

Harvest and residue collection activity may affect the nutrient cycles of forest ecosystems in a variety of ways whose effects are only partially understood. The nutrient impacts of intensive harvesting systems (such as clearcutting) with whole tree removal may be severe if short harvest rotations are employed. The impacts of less intensive harvest systems would be less severe, although the exact nature of harvest impacts on nutrient cycles is not well understood.

Harvesting may adversely affect wildlife populations if critical stands, such as those providing winter deer yarding areas, are moved. Similarly, some species of birds, such as woodpeckers, are dependent on rotten trees for food and habitat. Failure to leave some such trees would be detrimental to these populations. Finally, harvesting may affect other uses of the forest such as recreation.

Harvesting would create approximately 115 direct jobs and stimulate indirect positions as a result of the economic multiplier effect.

Because a wood-fired powerplant can burn wood of any quality, it creates silvicultural opportunities for the improvement of the forest. If sound harvest systems are employed and operations are well managed, both the economic value of the residual stand and its esthetic value can be improved. In addition, harvesting can improve the vigor of aging or overcrowded stands.

When harvesting is applied in a dispersed fashion and creates a patchwork of different habitat types, the diversity and number of wildlife generally increase.

If mill residues are used as fuel, the impacts of tree harvesting still occur, but they are not a direct result of energy production.

Transportation. Transportation of wood to a wood-fired powerplant will increase the number of large semi-trailer vans using the roads and streets of the fuelwood harvest region or between the sources of mill waste and the generating plant. In general, deliveries of wood to a powerplant will be dispersed throughout the day and impacts on traffic congestion should not be significant. Some increase in traffic noise levels will occur, however, as will relatively small increases in the emission of air pollutants.

Operation. The most significant environmental impacts resulting from operation of a wood-fired powerplant result from air pollutant emissions and solid waste disposal. Estimated air pollutant emissions from the proposed Maine plant are shown on Tables IV-19 and IV-20.

A plant similar to the one proposed for Maine would use about 1,275 gallons per minute of water and discharge 284 gallons per minute at not more than 68°F with resultant small changes in water quality. Water pollutants discharged are listed in Table IV-21. The powerplant would produce approximately 80 tons of ash per day, containing small concentrations of toxic metals. Properly landfilled, these substances should pose no hazard to drinking water or aquatic environments. If leachate from the landfill contaminated water supplies, damage to public health could occur. Similar air, water, solid waste, and socioeconomic impacts would occur from operation of a similarly sized plant in the Northwest.

Currently, many millwood residues from the wood products industry are disposed of in landfills or incinerated in bark burners which produce large quantities of air pollutants. Combustion of wood to produce power provides an alternative for the disposal of these residues. Combustion of the residues in wood-fired powerplants would reduce the need for landfill space and, because of the efficient combustion techniques and air pollution control which would be used, substantially reduce the emission of particulate matter into the air.

Footnotes

1/ Johnson, L. R., Simmons, G., and Peterson, J., Colleges of Forestry and Engineering, University of Idaho, "Unconventional Energy Resources," Northwest Energy Policy Project, Energy Supply and Environmental Impacts, Study Module III B Final Report, 1977, p. 113.

2/ Bonneville Power Administration, Branch of Power Resources, and U.S. Forest Service, Pacific Northwest Region, and Pacific Northwest Forest and Range Experiment Station, "Progress Report - Feasibility of a Forest Residue Powerplant," March 1979, p. 2-3.

3/ The Resource Policy Center, Thayer School of Engineering, Dartmouth College, "Draft Environmental Impact Statement: Advanced System Demonstration for Utilization of Biomass as an Energy Source in Westbrook, Maine," prepared under contract to The Rust Engineering Co., for the Fuels from Biomass Systems Branch, Division of Distributed Solar Technology, USDOE.

TABLE IV-19

EMISSION RATES FROM A PROPOSED
WOOD-FIRED PLANT

	Total Suspended Pariculates	Sulfur Dioxide	Nitrogen Oxide	Hydro-Carbons	Carbon Monoxide
SOURCE STRENGTHS 1/ (grams/second)					
Normal Operation 2/	9.5 3/	11.0 4/	57.9 5/	2.1 5/	18.1
Emergency Oil-only Operation 6/	0.05 7/	51.1	20.8	0.47	2.3
ANNUAL EMISSIONS 8/ (tons/year)					
Normal Operation 2/	320	370	1,930	70	600
Emergency Oil-only Operation 6/	1.7	1,700	690	16	77

1/ Based on EPA 1976 unless otherwise stated.
2/ Plant operating on 98.5 percent wood and 1.5 percent oil with full wood drying.
3/ Based on New Source Performance Standard for mixed fuel oil boilers of 0.1 pounds 10 6/ Btu (CFR 1977). New standards promulgated June 11, 1979, would restrict these emissions further.
4/ Includes contribution from sulfur in wood.
5/ Calculated by Otis Manar, Project Engineer, Rust Engineering Company, Birmingham, Alabama.
6/ Fuel oil is 0.7 percent sulfur.
7/ Based on EPA 1976 and assuming 99 percent removal of particulates by electrostatic precipitators and cyclones.
8/ Assumes plant operates 350 days per year.

TABLE IV-20

TRACE METALS IN WOOD-FIRED BOILER EMISSIONS

Metal	Emission Rate 1/ (lbs per year)
Copper	78
Arsenic	F49
Selenium	F134 2/
Lead	F10
Cadmium	F10
Nickel	205
Chromium	F5
Vanadium	F246

1/ Based on trace element composition of wood and oil. Assumes 350 days per year operation, oil comsumption not greater than 4 percent on a Btu-input basis, 70 percent of ash is flyash, and 90 percent particulate removal.

2/ Assumes 13 percent of selenium in wood is discharged to the atmosphere as a vapor.

TABLE IV-21

PROJECTED EFFLUENT OF A WOOD-FIRED POWER PLANT

	Plant Effluent (pounds/day)
Silica as SiO_2	229.0
Calcium as CaO	794.0
Magnesium as MgO	93.6
Iron as Fe_2O_3	52.5
Aluminumas Al_2O_3	48.7
Sodium as Na_2O	502.0
Potassium as K_2O	121.4
Sulphate as SO_4	407.5
Chloride as Cl	70.0
Phosphate as PO_4	75.0
Manganese as MnO	21.0
Titanium as TiO_2	trace
Vanadium as V_2O_5	2.37
Nickel as NiO	0.024
Zinc as ZnO	2.0
Suspended Solids	210.0
Biological Oxygen Demand	28.0

(8) End-Use of Wood to Displace Electrical Usage

Technology

There are a number of applications in which firing wood or wood-derived fuels could displace significant electrical loads. These are residential and commercial space and water heating; industrial mechanical energy produced by firing wood to generate steam which could drive steam powered equipment, displacing electrically driven equipment; industrial process heat; and cooking.

The hardware for use of wood and wood-derived fuels in these applications is either readily available or could be made available quickly. Basically, the use of wood would largely be a return to the types of devices which were used prior to the advent of petroleum and electricity as major energy sources. For example, wood stoves and fireplaces would replace electric stoves and baseboard heaters in homes. The technology for large-scale, wood-fired steam facilities is essentially the same as for power generating facilities except the steam is used for process heating or for driving mechanical equipment instead of operating a turbine generator. Similar, but smaller, units might be used to provide steam to heat a large building. For residential heating, fireplaces equipped to improve their efficiency, stoves, and wood or sawdust furnaces may be used.

Potential

The potential for wood as an energy resource was discussed in the section on wood-fired electrical generation. End-use applications constitute an alternate use of this resource, albeit one that conflicts with other uses.

Costs

The capital costs of a plant producing steam only, equivalent in size to the proposed Westbrook, Maine, cogeneration facility described in the section on wood-fired electrical generation, would be about $53 million, about $10 million less than the proposed cogeneration facility, but operating costs would be only marginally less. Costs of modifications to fireplaces to make them more efficient are $350 to $500, while wood stoves range from $15 to more than $900, depending on size and features.

The cost of wood fuel varies widely. It ranges from "free for the taking" in the case of some mill waste and wood harvested for personal use in publicly owned forests, to the currently advertised prices of $25 to $85 per cord (a cord is a quantity of wood measuring 4 feet by 4 feet by 8 feet) for cut firewood in Portland, Oregon.

Environmental Impacts

Environmental impacts from steam generating units using wood fuel would be very similar to those described previously in the section on wood-fired electrical generation, except the need for cooling water and the rejection of waste heat would be much less.

There are no Federal or state regulations that control air emissions from residential heating units. Thus, the operation of wood stoves could deteriorate air quality, especially in communities where they are extensively used. Particulate emissions from wood stoves are primarily fine, highly respirable, and contain benzo(a)-pyrene, a known carcinogenic compound. Amounts of air pollutant emissions produced by burning wood in a fireplace are shown in Table IV-22. Ash disposal could be a problem for landfill areas.

Impacts on the forest resource are of primary concern. Uncontrolled firewood harvest could threaten the resource with nutrient losses, erosion, overcutting, and mismanagement.

Use of wood for residential heating involves a change in lifestyle which some persons may not be willing or able to undertake.

TABLE IV-22

Air Pollutant Emissions from Residential Fireplaces

Pollutant	Pounds Per Ton of Wood Burned 1/
Particulate	20
Nitrogen Oxides	1
Hydrocarbons	5
Carbon Monoxide	120

1/ Types of wood available in the Northwest range from about 16.2×10^6 Btu/ton to 19.4×10^6 Btu/ton.

Source: U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Third Edition, August 1977.

(9) Geothermal Generation.

Technology

Geothermal electrical generation in the Pacific Northwest will probably be based on hot-water-dominated geothermal reserves of high and intermediate temperature, rather than on vapor-dominated systems or hot dry rocks. There are no known vapor-dominated systems in the Pacific Northwest except those in national parks. Although there is a substantial amount of energy in hot dry rocks, it is not economically feasible to extract this energy with current technology.

Hot-water systems are divided into three temperature ranges according to use:

a. above 150°C, considered for generation of electricity;

b. from 90°C to 150°C, considered for space and process heating; and

c. below 90°C, likely to be utilized for heat only in locally favorable circumstances.

There are two methods which can be applied to the production of electricity from hot water systems. In the open (or flashed steam) method, part of the hot geothermal water vaporizes to steam because the pressure on the water is reduced as it is extracted from the geothermal reservoir. This steam drives a turbine-generator. Exhaust steam from the turbine is sent to a condenser where it is condensed and discharged. This method generally requires a geothermal water temperature above 250°C. For the intermediate temperature range of 150°-250°C, the binary cycle is being developed. The binary cycle employs a secondary working fluid heated by geothermal hot water that circulates through the turbine-generator and a condenser to produce electricity. The binary process, though more complex than the flashed steam method, has the advantage of protecting the turbine from the corrosive, erosive, deposit-forming impurities in geothermal water. The binary cycle is not commercially viable at present, but a demonstration plant is under construction in the Raft River area of Southern Idaho.

Potential

The United States Geological Survey (USGS) has undertaken a systematic effort to estimate geothermal resources. These estimates were documented in Circular 726 (USDI, 1975) and were updated and refined in Circular 790 (USDI, 1978). Several other estimates of geothermal resources in the Pacific Northwest have been made which vary according to the assumptions and time periods used, but most of these estimates were based on outdated information from Circular 726.

Based on the latest USGS estimates of potential electrical energy available from known resources, it appears that the greatest near-term potential for electrical generation development lies in Oregon and Idaho, with very little development potential presently identified for Montana and Washington. Identified hot water systems greater than 150°C indicate potential for 2424 MWe for 30 years for the Pacific Northwest. Circular 790 also estimates the undiscovered accessible resource base for several geographic provinces of the Pacific Northwest, including the Cascades, Oregon Plateaus, Snake River Plain, and the Northern Rockies. There is a likelihood of five times more geothermal resources than are presently identified, although considerable test drilling will be required before these resources can be accurately identified. However, it appears highly unlikely that all the potential geothermal energy will be developed because of esthetic, environmental, and other reasons. The percentage of regional electrical demands which can be met from this source in the next 20 years will be relatively small, and depends heavily on the commercialization of the binary cycle turbine among other factors.

The regional potential which is likely to be developed is being estimated by BPA under contract with the Oregon Institute of Technology and will be made available in August 1980.

Costs

The economics of the use of geothermal hot water for electricital generation are dependent on resource characteristics. Since detailed data on geothermal resources in the Pacific Northwest are not available, arbitrarily a resource with a temperature of 177°C and medium salinity (10,000 parts per million dissolved solids) was assumed for purposes of calculation. The bus bar energy costs have been estimated for such a hypothetical geothermal hot-water powerplant using the binary cycle. Bus bar costs range between 32 and 41 mills/kWh for 1985 under these assumptions. Capital costs are approximately $640 per kW (1976 dollars) of capacity for a plant going on line in 1985.

A large uncertainty in the estimates of total cost arises because of unknowns about the fixed exploration cost for the resource, the cost of drilling wells which turn out to be nonproductive, and the average drilling costs of the production and injection wells.

Environmental Impacts

In recovering geothermal energy, the environmental impacts occur from drilling, testing, construction, and operation. Most of the impacts due to drilling and testing are similar for both direct heat utilization and electrical generation except that a deeper hole is usually drilled for electrical generation. The principal differences in impacts lie in construction and in the utilization of the resources.

Due to limited electrical generation from binary cycle plants, there is a lack of information concerning operational and environmental impacts. Projections must be made from the vapor dominated systems such as the Geysers in California. (See Tables IV-23 and IV-24.)

Impacts of drilling and testing are principally degradation of surface and groundwater quality and noise from the drilling equipment. Pollutants, including heavy metals, can leach from the drilling mud pits into groundwaters and contaminated water from well cleanout and blowout can run into surface waters or drain into aquifers.

Construction impacts for geothermal generating plants will be those typical of constructing industrial facilities; namely, emissions from equipment, noise, dust, and the socioeconomic effects of employment of construction workers.

The major operational air quality impacts are: hydrogen sulfide (H2S) which has an offensive odor and can affect plant growth; particulates which cause visibility reduction and can be toxic to plants and animals; and water vapor which may cause fog. Geothermal reservoirs may contain boron which can cause leaf burn in plants, toxic mercury and arsenic, and radioactive radon. Cooling tower plumes contain dissolved solids and biocides and fungicides which can damage plants and cause corrosion.

The heated water discharged from a geothermal generating plant can have beneficial impacts. Some of this warm water can be used to promote the growth of commercially viable aquatic species such as cultured shrimp and catfish; an application which is currently being tested at the Raft River project.

Both surface and groundwaters can be affected by geothermal development. The major pollutants in geothermal fluids vary with site but they may contain several heavy metals and be highly saline. Both the metals and salinity could be hazardous to humans, plants, and animals. Since reinjection will be the most likely method of liquid disposal, contamination surface waters will be avoided except for accidental spills, which can be minimized by diking. The main problems with reinjection are the potential for aquifer contamination and for increased subsidence and seismicity.

A prototypical 250 MWe geothermal power plant will permanently disturb approximately 1,250 acres, although land use can be minimized by utilizing existing roads in the area and by locating several wells on one wellpad. However, the main questions on land use relate not so much to the amount of acres disturbed by geothermal development, but to the effects on the site itself. The most important issues are ecological disturbance, increased erosion, visual impact of the development, competition with other land uses, and potential for

TABLE IV-23

PACIFIC NORTHWEST 1,000-MWe GEOTHERMAL POWER
GENERATION TRAJECTORY RESIDUALS

Residual	Extraction	Conversion	Total
Air Effluents (tons/year)			
CO_2, N_2, H_2, Ar	4,400	664,000	668,000
Sulfurous	270	39,200	39,500
Nitrous	370	54,000	54,400
Hydrocarbons	270	40,000	40,300
Particulates	--	--	--
Water Effluents (tons/year)			
Inorganics	0	0	0
Suspended Solids	0	0	0
Organics	0	0	0
Solids (tons/year)	0	0	0
Thermal (10^9 Btu/year)	NA	153,000	153,000
Land Disturbance			
Temporary (acres/year)	0	0	0
Permanent (acres)	180	4,800	5,000
Water Consumption (acre-feet/year			
To Air	390	48,600	49,000
To Water/Ground	0	0	0

NA = Not Available.

Based on: University of Oklahoma, 1975, p. 8-1 to 8-29.

TABLE IV-24

ENVIRONMENTAL EFFECTS OF A 1000-MWe GEOTHERMAL POWERPLANT 1/

	Extraction Drilling and Production	Transportation Pipeline	Conversion Heat Exchanger and Turbine
Air	Radium and radon gas, CO_2, 2/ H_2S, 2/ H_2, CH_4, C_2H_6, N_2, NH_3, water vapor; venting formation dust during air drilling.	Steam venting; residuals same as those mentioned under extraction.	Water vapor, waste heat H_3BO_3, HF, Hg, 2/ H2, argon;
Water	Nongaseous radionuclides (226 Ra), B, Li, Na, K, Rb, CS, MG, F, Cl, Br, I, NH_4, SO_4, AS 2/, Hg 2/, silica 2/, H_2S 2/; groundwater contamination.	None	Blowdown residuals, Carbonates, PO4 ammonia, NO2, SO4, NO3, chloride, calcium, Mg, silicon, boron total solids, organics and volatile solids, heavy metals (CU, Ni, Fe, Zn)
Solid Waste	Mud	None	None
Land Use	Clearing for drill sites and mud-cooling ponds, facilities, and roads.	Clearing of land for pipe installation; reduction in plant and animal habitat.	Land utilization for power house and cooling units. 2/ Total land use: 3,000 to 5,000 acres.
Noise	Noise from muffled testing wells and air-drilling noise are significant during drilling. Noise from discharge vents during interim between drilling and production.	Venting 2/	Operational venting 2/

1/ Will vary to some degree depending on geophysics and geochemistry of the hydro-thermal reservoirs.
2/ Significant (no waste-treatment technology taken into consideration).

Adapted from: Equitable Environmental Health, 1976, p. 27.

disturbance of cultural and historic sites, all of which are site-specific.

The noise which occurs from operation of a geothermal electrical generation plant with a liquid dominated system will be less than experienced from the vapor dominated systems.

(10) End-Use of Geothermal Energy to Displace Electrical Usage.

Technology

Geothermal energy can be used in lieu of electricity for space heating and air conditioning, refrigeration, industrial process heating, and agricultural/aquacultural uses. The exploration, drilling, testing, extraction, and disposal aspects of geothermal development for end use applications are essentially the same as its use for electrical generation. The principal difference is that nonelectric utilization of geothermal energy requires a transportation system to the point of use other than power lines, and requires conversion of existing systems to use geothermal hot water energy. It is not technically or economically feasible to transport the low grade geothermal energy found in the Northwest over great distances because the water temperature drops about 0.5 to 1°C per mile transported, which rapidly degrades its usefulness.

A comprehensive assessment of the present state of the art for geothermal development can be found in the Jet Propulsion Laboratory documents. 1/

Potential

Numerous studies have been made but have resulted in little conclusive evidence concerning the region's geothermal energy potential. 2/ Surface and shallow well phenomena and heat flow measurements can only provide general information. Of the test holes that have been drilled to date in the region, only the wells in the Raft River area in Idaho have produced water as warm as 150°C (300°F). Over 90 percent of the geothermal resources in the Northwest are estimated to have water temperatures less than 150°C. 3/ Futhermore, it is difficult to predict the length of time that a prospective geothermal resource will produce, which makes it difficult to compute its cost-effectiveness.

A study by the University of Idaho 4/ surveyed Northwest industries to determine whether or not moderate temperature geothermal energy might furnish a significant portion of the energy demand for specific industrial processes. None of the industries surveyed had a demand large enough to support geothermal development independently. However, groups of industries may be capable of economically supporting geothermal development. 5/

The potential impact of geothermal energy for space heating and cooling was estimated in a study for the Northwest Energy Policy Project. 6/ The study assumed that 16 percent of the population in the Northwest lies within a 50 mile radius of a geothermal energy source. On this basis, it was estimated that geothermal energy could repace 3.15 percent of the region's total energy consumption for space heating and cooling. BPA has contracted with the Oregon Institute of Technology to specifically determine the potential for geothermal energy for displacement of electrical usage. Results of this study are expected in February 1980.

Costs

Because of transportation costs, as the demand per user increases, the cost per unit of delivery of geothermal energy decreases dramatically. For this reason, large commercial or industrial users are more economical applications for geothermal energy than residential applications. Costs also increase rapidly as the distance over which the geothermal water must be transported increases. Hence, industrial applications of geothermal heat close to its source are most desirable.

Major capital costs for non electric geothermal use, as estimated by the Northwest Energy Policy Project (NEPP), are shown in Table IV-25. 7/

TABLE IV-25

MAJOR ECONOMIC COSTS FOR NON-ELECTRIC UTILIZATION OF GEOTHERMAL ENERGY*

Supply/Disposal			$27,500,000
Transportation			
12-inch pipe installed		$75/ft	
30-inch pipe installed		$133/ft	
Distribution	$2000/installation		
Conversion	$2000 per 30,000 Btu/hr. of installed capacity		

* Assumes a system of 25,000 gallons per minute capacity with reinjection at the well-site.

Energy costs vary widely depending on the temperature of the hot water resource, the distance over which it must be transported, the steadiness of demand for the energy, and other factors. These costs vary from approximately $3 per million Btu (equivalent to about 10 mills/kWh 8/) for 250°F water where the transportation distance is negligible, to approximately $30 per million Btu (equivalent to about 100 mills/kWh) for 150°F water transported over 50 miles using 12-inch transite pipe. These costs include amortized distribution costs of $2000 per installation and assume reinjection at the geothermal well site. An additional $2,000 per 30,000 Btu per hour of installed capacity was estimated for conversion of existing heating systems to use of geothermal hot water. Amortized over 30 years, this would add an additional cost of $2.38 per million Btu (equivalent to 8 mills/kWh) to the above energy costs. Use of ductile iron pipe could substantially reduce these costs and the feasibility of its use is being studied. More complete cost information can be found in NEPP. 9/

Environmental Impacts

Impacts of exploration, drilling, and testing for geothermal end use are essentially the same as for geothermal electrical generation, and are not be repeated here.

Construction impacts result from establishing a transportation and distribution system to carry the hot geothermal fluid from the wells to the points of end-use. These impacts would be similar to those from constructing water mains, and would consist principally of noise, dust, and emissions from vehicles. Disruption of traffic would be a nuisance while lines are laid in or across streets and roads. Land would be temporarily disturbed along the routes of the transportation and distribution pipes.

The only significant environmental impact associated with the use of geothermal water is related to the disposal technique chosen. Possible disposal techniques include reinjection and storm drains. A home with a peak heating demand of 30,000 Btu/hr requires approximately 640 gal/day of 121°C (250°F) water (assuming an overall system efficiency of 75 percent). Disposal via storm sewers or separate disposal lines to a river or lake has drawbacks such as the release of excessive flouride. 10/ Thermal pollution must also be considered as the reject temperature is expected to be on the order of 27° to 38°C (80 to 100°F). Chemical and thermal pollution of rivers has adverse impacts on aquatic life, wildlife, and recreation. If deep well reinjection is the method of disposal, then no environmental impact of disposal is expected. Reinjection is desirable for recharging the aquifer.

Footnotes

1/ Jet Propulsion Laboratory (1975). Geothermal Program Definition Project. Status report, JPL #1200-205. Pasadena, California.

2/ White, D. E. and D. L. Williams, editors. Assessment of Geothermal Resources of the United States - 1975. Geological Survey Circular 726. Nichols, C. R. & K. W. Hollenbaugh (1975). Geological aspects of an assessment of the national potential for non-electrical utilization of geothermal resources. Aerojet Nuclear Company, Idaho Falls, Idaho. ANCR-1213. June, p. 251.

3/ White and Williams, op cit.

4/ Gerick, J. (1976). Potential Utilization of Geothermal Energy by Idaho Industries. M.S. Thesis. Department of Chemical Engineering, University of Idaho.

5/ U.S. Department of Energy, BPA, Industrial Electrical Cogeneration Potential in the BPA Service Area, Phase 1, Technical Analysis, prepared by Rocket Research Company, Jan. 19, 1979.

6/ Johnson, L. R., Simmons, G., and Peterson, J., Colleges of Forestry and Engineering, University of Idaho, "Unconventional Energy Resources," Northwest Energy Policy Project, Energy Supply and Environmental Impacts, Study Module III-B Final Report, 1977, p. 113.

7/ Ibid.

8/ The costs given in mills/Kwh are the costs of equivalent amounts of electrical resistance heat, which operates at near 100 percent efficiency in converting electrical energy to heat.

9/ Ibid.

10/ Young, H. W. and R. L. Whitehead (1975). Geothermal Investigations in Idaho, Part 2, an Evaluation of Thermal Water in the Bruneau-Grandview Area, Southwest Idaho. Idaho Dept. of Water Resources, Water Information Bulletin No. 30.

c. Storage Technologies.

(1) Pumped Storage.

Technology

Pumped storage plants involve the use of two reservoirs at different elevations. Energy is stored by pumping water frot the lower reservoir to the higher one. Electricity is generated when the water from the upper reservoir passes through a turbine on the way to the lower reservoir. Pumped storage plants are net energy users; it takes approximately 3 kWh to pump water sufficient to generate 2 kWh. Possible sources of pumping energy in this region would be off-peak power from conventional hydro or thermal facilities or power from intermittent resources, such as wind. A single device, the reversible pump-turbine, may perform both pumping and generating functions. These can be quickly interrupted while pumping to shed load if a forced outage on the system requires this action. At sites where the head is much above 2000 feet, separate pumps and turbine generators are required.

Potential

The topography of the Pacific Northwest makes this region well suited to the development of pumped storage and a vast majority of the potential sites have been identified. These sites would be suitable for daily/weekly cycle plants which would generate for 6 to 8 hours on weekdays and pump at night and on weekends.

The region's total technical potential for pumped storage has not been determined, but the U.S. Army Corps of Engineers has estimated that the total capacity of sites capable of supporting projects of at least 1,000 MW is nearly 2 million MW. 1/ A total of 12 sites have received serious consideration for pumped storage plants. 2/ If these or comparable sites were developed, they would have a maximum estimated capacity of over 35,000 MW.

Costs

The costs associated with pumped storage plants are site-specific, depending principally on the size of newly constructed reservoirs and on the vertical and horizontal distance between the reservoirs. The cost data currently available to BPA on pumped hydro exhibit inconsistencies and are not sufficiently documented. At 1976 price levels, these data indicate that capital costs range from \$230 million to \$1,022 million and annual costs range from \$20 to \$35 per kilowatt for federally-financed plants. 2/

Environmental Impacts

Environmental impacts would result from construction of access roads and transmission lines, dams, and the reservoir. The nature and extent of the impacts would, vary considerably from site-to-site, but would, among other impacts, include noise, dust, and equipment emissions common to major construction projects. Downstream siltation and pollution may occur. Construction may result in significant influxes of workers and associated socioeconomic impacts.

Fairly large amounts of land may be inundated by the reservoirs, depending on the site. At eight potential sites utilizing existing reservoirs or lakes as the lower reservoirs, between 0.05 and 0.47 acres per MW of capacity would be required for the upper reservoir. Nearly all the projects would alter fish habitat in both the upper and lower reservoirs. Operation of a facility along a stream could change instream flows and exacerbate problems during low-flow periods. Pumping could increase mortality of juvenile fish, which would further threaten the region's anadromous fish resource.

Pumped storage development would expose mudflats whenever the water was drained from the upper reservoir. The daily fluctuations in water level would be especially great at daily/weekly cycle plants and would have a great visual impact on sites now favored for hiking and backpacking. The development of seasonal cycle plants would alter existing uses of the reservoir and may increase some recreational opportunities.

Given the remote location of many sites in the region, wildlife species, including some which are rare and endangered, may be affected adversely by the development and operation of a facility. A number of proposed sites are currently used as winter range by big game. Some species, such as upland game birds, might benefit from pumped storage development, but on an average, the negative impacts on wildlife would apparently outweigh the positive impacts.

Footnotes

1/ U.S. Army Corps of Engineers, "Pumped Storage in the Pacific Northwest: An Inventory," (Portland, Oregon; U.S. Army Corps of Engineers, 1976), p. 35.

2/ See U.S. Army Corps of Engineers, Pacific Northwest Regional Pumped-Storage Study (1978); Chelan County, Washington, Public Utility District No. 1, Antilon Lake Pumped Storage Project Status Report (Wenatchee, Washington, September 22, 1976); Douglas County, Washington, Public Utility District No. 1, Brown's Canyon Pumped Storage Project (East Wenatchee, Washington, February 1975); and U.S. Department of the Interior, Bureau of Reclamation, Report on the Western Energy Expansion Study (1977).

(2) Compressed Air Energy Storage.

Technology

Compressed air energy storage (CAES) uses off-peak power to compress air and pump it into huge underground caverns for storage. During subsequent peak load periods, the compressed air is released from storage, mixed with fuel such as gas or oil, burned, and expanded through a combustion turbine to generate power. During the expansion process the compressor is disengaged, allowing the part of the turbine's power which would normally go to drive the compressor to help drive the generator. This increases the net output up to three times that available from a similarly sized combustion turbine which might otherwise be used to produce peaking power. 1/ To produce 1 kWh of peaking power using such a system requires 0.72 kWh of electrical input to compress the air plus 4000 Btu's of fossil fuel.

The options available for compressed air storage pertain to the type of storage reservoir used. The most suitable storage reservoirs are mined hard rock caverns, aquifers, and solution-mined salt caverns. Natural caverns and depleted oil and gas fields are also being considered, although they do not seem to offer great potential for widespread usage. Compressed air storage can be used to meet peak loads and to improve system load factor.

Potential

Since the Pacific Northwest is ideally suited for pumped storage, the region has not been extensively considered for CAES applicability. A survey of current literature indicates that this region does not have sufficient salt deposits for salt cavern storage. A state-by-state analysis of drilling records and seismic information is necessary to determine the availability of suitable aquifers for storage. The potential for storage in conventionally-mined caverns requires detailed geological analysis. Although it is technically possible to excavate a cavern virtually anywhere in this region for use as storage, this would increase the capital costs considerably and might make CAES uneconomical.

CAES, along with other storage systems, could be a means to utilize surplus energy resulting from meeting minimum flow requirements during periods of low power demand.

Costs

Economic assessments to date indicate that implementation of CAES within the next decade will probably be limited to exceptionally suitable sites in the Northeastern United States. The consensus is that 1985 will be the earliest that the U.S. will utilize CAES. 2/

A single source for capital and annual costs is unavailable. The cost estimates presented should be used only for general information and are not suitable for comparison with other costs.

Brown Boveri, who built the 290-MWe facility in Huntorf, Germany, estimates capital costs for a 220-MWe U.S. plant at $300/kW in 1979 dollars. This represents the most recent price estimate available, and includes $60/kW for developing a suitable cavern for storage. 3/ Assuming public financing for 35 years, a capacity factor ranging from 10 percent to 20 percent, an energy balance as indicated in the preceding, use of fuel oil, and operating and maintenance costs for a simple combustion turbine, the bus-bar energy costs range from 40 to 55 mills/kWh. These values include current BPA secondary energy rates and current oil prices. The National Energy Act prohibits the use of oil or natural gas in new electric utility generating facilities, unless an exemption is granted on the grounds that an oil or gas-fired plant is substantially less expensive over a given period of time than a plant fired with alternate fuel.

Environmental Impacts

Many of the environmental impacts of CAES are the same as those for combustion turbines used for peaking generation, and the reader is referred to the discussion of combustion turbines for these impacts.

The storage chamber is the most distinctive feature of CAES facilities and has the greatest potential for environmental impact. Contamination or alteration of ground water flow is of primary concern during construction of the storage cavern and operation of the facility.

Caverns created by the solution mining of salt beds present brine disposal problems. The volume of brine generated is typically ten times the volume of the cavern. Unless a depleted oil or gas field is available nearby to receive the brines, they will have to be injected into an aquifer.

Aquifer storage also has undesirable features. The increased pressure in the aquifer is likely to affect adjacent freshwater wells. If the aquifer is saline, there is a potential for contamination of nearby freshwater aquifers.

Footnotes

1/ Albert Giramonti, Lessard, Robert D., and Hobson, Michael J., "Conceptual Design of Underground Compressed Air Storage Electric Power Systems," Proceedings of the 12th Intersociety Energy Conversion Engineering Conference, Vol. 1 (1977), p. 592.

2/ "Utilities Tout Compressed Air Energy for Peak Power and Fuel Savings," Engineering News-Record, Vol. 200 (May 25, 1978), p. 14.

3/ Stys, Z. Stanley, Letter to Bonneville Power Administration, April 25, 1979, Bonneville Power Administration Library.

(3) Batteries.

Technology

Battery storage systems, while still in the developmental stage, appear to be well-suited for utility load shaping applications. Surplus electrical energy is converted via electrochemical reactions to chemical energy, and then, when needed, reconverted back to electrical energy. Battery storage systems are modular in nature and may be installed near residential load areas since they are quiet and compact. They have no mechanical components and respond rapidly to changing load needs.

Conventional Batteries. Presently, the lead-acid (lead-antimony) battery is the only commercially available load-shaping battery for utility applications. Its performance characteristics are shown in Table IV-26. While life expectancy for these batteries is 10 years, changes in design to lead-calcium by Westinghouse 1/ have doubled the life expectancy to 20 years. The new batteries are designed to be modular in nature in blocks of 10 to 20 MWe with 3-5 hours discharge time and a 1:1 discharge/charge time ratio.

The nickel-cadmium battery has a greater power density and a longer cycle life than the lead-acid battery, as shown in Table IV-26, but its high cost is prohibitive for utility applications.

TABLE IV-26

ELECTROCHEMICAL ENERGY STORAGE
PRINCIPAL CHARACTERISTICS

	Capital Cost ($/kW)	Life (cycles)	Energy Density (Whr/lb)	Power Density (W/lb)
Conventional:				
Lead-Acid	500	1500	35	100
Nickel-Cadmiu	1500	2000 +	15	300
Developmental:				
Metal-Air	500	1500 +	60	40
Alkali-Metal	150	2000 +	100 +	100 +

Source: Lewis and Zemkoski, 1973, p. 5.

Developmental Batteries. Research on various types and designs of batteries is in progress to reduce size and weight, increase storage capacity, reduce cost, and extend service life.

Potential

The commercial availability for a storage battery load-leveling system is projected for 1984. In 1979 DOE initiated a program for the design and construction of a 10 to 20 MWe demonstration plant. Acceptance testing is scheduled for 1982.

Commercial systems for utility application will have an energy density average of 200 to 500 MWh with overall efficiencies of between 65-75 percent. Design and licensing followed by construction will, on the average, require 1 year and 2 years, respectively.

Costs

Capital requirements will be approximately $275-300/kW in 1977 dollars.

Environmental Impacts

The impacts of operating storage battery load-leveling systems are relatively minor. Small amounts of waste heat may be produced in some cases, but normally noise and visual pollution are negligible. There is the potential for pollution problems associated with cell failure, i.e., heat release, corrosive material leakage, and toxic vapor emission. However, planning for these eventualities in terms of cell design parameters, modular enclosures, and safety instrumentation with automatic shutdown tend to minimize their potential impact.

The more severe environmental issues are perhaps associated with the manufacturing processes: i.e., mining considerations, air and water pollution by heavy metals, and acid leakage. The usual construction disturbances can also be expected for an installation of this type.

Footnotes

1/ Maskalick, N. J. "Lead-Acid Load-Leveling Batteries: A New Design for 20-Year Service Lifetime," A Westinghouse sponsored paper presented at the American Power Conference in Chicago, April 1979.

2/ Lewis and Zemkaski, 1973. p. 5.

3/ Electric Light and Power, 1975. p. 2.

4/ Electric Power Research Institute, "An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities." EPRI Report No. EM-264. July 1976, Vol. II.

5/ Schneider, Thomas R., "Storage as an Energy Strategy for Utilities," Proceedings of the Fifth Energy Technology Conference, February 27-March 1, 1978. Washington D.C. pp. 379-386.

d. Nonrenewable Resources.

(1) Conventional Thermal Generation.

(a) Nuclear Generation.

Technology.

Nuclear generation involves (1) plant construction; (2) mining and preparation of the uranium; (3) fissioning of the fuel to generate electrical energy; (4) disposal of the spent fuel; and (5) ultimate decommissioning of the generating plants.

The uranium for generating plants serving the BPA service area will generally come from outside the region, although there are a few scattered deposits in Washington and Montana. It is mined by both underground and open-pit techniques. New developments in the technology of mining uranium may reduce capital and labor demands, as well as permit higher recovery rates from the lower-grade ore.

After the ore has been extracted, it is refined, processed, enriched, and encased in zirconium tubes before it is placed in the reactor. In the reactor, atoms split, or fission to produce energy, which creates steam to operate a turbine, which in turn drives an electrical generator. The steam is condensed for reuse by water recirculated through ponds or giant cooling towers which give off water vapor. Makeup water is generally drawn from a nearby river. There is some blowdown from the condensing and cooling systems which can contain impurities, and requires treatment and disposal. As with most large thermal generation, nuclear plants are operated as baseload units.

The spent fuel must be removed from the reactor at scheduled times and replaced during refueling and maintenance outages. Spent fuel elements are stored in the spent fuel pool, under water, for a least 30 days until the short-lived fission products have decayed and the radioactivity level is reduced. There is currently no spent fuel reprocessing available in the Pacific Northwest. Therefore, all spent fuel is being stored in temporary storage facilities until suitable means of disposal are found. Some states in the region are contemplating a moratorium on nuclear plant siting until suitable radioactive waste storage facilities have been constructed. Other states are taking action to restrict the transportation of hazardous wastes within their boundaries, since radioactive material presents potential hazards to human health if it is not properly isolated.

Potential

Domestic resources are essentially assured to supply the lifetime uranium needs of all reactors currently committed, as well as for some additional plants. Uranium export policies of foreign countries are dependent on political and economic factors.

Present day light water reactors cannot be considered long-term energy solutions in themselves since the ultimate uranium supply is limited. Rather, they represent interim resources to provide currently economical power which could ultimately be replaced by a longer-term, renewable energy sources, including breeder reactors.

The current leadtime for bringing nuclear plants on-line is about 12 to 14 years. Thus, any moratorium on the granting of siting permits would have consequences felt more than a decade in the future.

Costs

The cost of nuclear energy does not generally depend on the cost of uranium which represents only a fraction of the total power cost. However, costs of all fuels are gravitating toward the higher prices dictated by the OPEC oil cartel. Despite further price increases, uranium should remain the most economical fuel for power generation.

The total busbar energy costs have been stimated for a hypothetical 1,250-MWe nuclear powerplant, varying by ownership, financing, and state. These costs range from a low of 11.4 mills/kWh for a federally owned facility financed at 6.5 percent in 1976, to a high of 66.4 mills/kWh for a privately owned plant in Oregon financed at 9.5 percent in 1995.

Environmental Impacts

The impacts of nuclear generation are associated with three distinct phases: construction of the plant, operation and maintenance (which includes fuel acquisition and waste management), and decommissioning. This discussion presents general impacts of nuclear generation. Site-specific impacts of existing and developing nuclear plants are discussed in Chapter IV.A. Residuals of a 1,000 MWe plant are provided in Table IV-27.

Plant Construction. Plant construction has similar impacts on air, land, and water as does coal-fired generation. A prototypical 1,250-MWe nuclear plant will temporarily disturb 55.5 acres and permanently disturb 710 acres. A construction crew of 1,000 employees to erect new plants will temporarily increase the local population and might stress services and facilities, especially if the plants are located in small, rural communities.

Operation and Maintenance. The environmental impacts from operation of nuclear generation result from each phase of the fuel cycle: mining and milling, irradiation in the reactor (conversion), and spent fuel storage.

Mining and Milling. Surface mining has a number of adverse effects on the environment. The mining necessary to supply a 1,000-MWe nuclear plant temporarily disturbs 55.5 acres per year, and permanently disturbs 4.4 acres per year. Air residuals originate from the diesel-powered equipment and wind erosion, although dust suppression practices, reclamation, and revegetation of mined areas can reduce the particulates generated by wind erosion. Water pollution occurs from suspended solids produced by runoff from piles of overburden and the mined surfaces.

Radiation exposure is strictly limited for underground uranium miners, and is reduced by ventilation. Radiation hazards are not a problem in the U.S. low-grade open-pit mines.

The milling process produces tailings, or low-level radioactive wastes, which must be stabilized to prevent wind and water erosion.

The residuals from transportation are negligible.

Conversion. Under normal operating conditions a nuclear reactor does not discharge radioactive steam to the environment. The risk associated with accidental radiation exposure is very low. No significant environmental impacts are anticipated from normal operational releases of radioactive materials. The estimated dose to the population within 50 miles of a plant due to operations can range from 3.9 to 15 man-rem/year.

Water consumption for cooling or other purposes draws between 19 and 36 acre-feet of water per year per average MW from local rivers or cooling ponds. Water intake structures may lead to some loss of lower trophic level life in bodies of water. There is some destruction of plankton, small fish, larvae, and fish eggs. Water consumption does not constitute a permanent loss to the environment, but only a very small change in water distribution. A nuclear plant releases approximately 50.8×10^9 Btu/year heat per average MWe. Algal blooms and some of their attendant problems may occur when heated water is discharged from the plant. If closed system cooling ponds are used, this will not affect local aquatic systems. Heat will also be discharged to the air through mechanical or natural draft cooling towers. There is a possibility of increasing fog in winter on highways a few miles from the plants in areas where natural fog occurs.

The cooling system can also result in chemical discharges to the environment from blowdown to remove impurities in the system.

Spent Fuel Storage. Spent fuel and other radioactive solid wastes from plant operations will require disposal. A nuclear plant produces approximately 26.4 curies/year of radioactive solids per average MW. For an 1100-MWe plant, about 60 fuel assemblies, or about 8 tractor-trailer loads, are used per year. Spent fuel must be either reprocessed to recover uranium and plutonium or treated as waste without reprocessing. All residual wastes and other irradiated materials must be stored so that they will be isolated from the environment until their radioactivity declines. Long-lived radioactive wastes must be isolated for thousands of years, thus special measures are necessary to contain these wastes.

Research continues on methods of storing radioactive waste. A variety of methods are currently under study by DOE. The most promising method at present appears to be geologic storage. A choice of storage methods will ultimately be made by the Federal government.

Decommissioning. The decommissioning or dismantling of a nuclear plant will occur when a plant no longer meets its owner's requirement, is obsolete, or no longer economic. All fuel is removed. The plant is then sealed and cooled for 10 years, requiring continuous monitoring and confinement. When the containment building is ready to be entombed, it is brought down (which has construction-like impacts), mounded over with clean rubble and fill. This area must be able to withstand natural forces for 200 years with no maintenance and some site monitoring.

If the reactor vessel is to be completely dismantled, there are problems associated with shipping and burying radioactive components of the reactor.

Estimates of decommissioning costs range from $4-50 million, and can cost up to 15 percent of construction costs, depending on the method of decommissioning employed.

TABLE IV-27

PACIFIC NORTHWEST 1,000-MWe NUCLEAR POWER GENERATION TRAJECTORY RESIDUALS

Residual	Extraction	Processing	Transportation	Conversion	Total
Air Effluents (tons/yr)					
Sulfurous	50	4,800	Negligible	--	4,900
Nitrous	23	1,300	Negligible	--	1,300
Hydrocarbons	1.8	13	Negligible	--	15
Particulates	--	1,200	Negligible	--	1,200
Water Effluents (tons/yr)					
Inorganics	0	100	--	0	100
Suspended/Dissolved Solids	26,400	--	--	344 1/	26,700
Organics	--	--	--	59	59
Solids (tons/yr)	3,100,000	73		0	3,100,000
Radioactive (Curies/year)					
Gaseous	75	367,000	--	2/	367,100
Liquid	2	2,500	--	2/	2,500
Solids					
High-Level	0	1.4×10^8	--	0	1.4×10^8
Other-than-high-level					
Thermal (10^9 Btu/year)					
Land Disturbance					
Temporary (acres/year)	55.5	0	0	0	55.5
Permanent (acres)	4.4	9.7	NA	700	712
Water Consumption (acre-feet/year)					
To Air	200	280	0	19,400	19,900
To Water/Ground	380	33,900	0	11,600	45,900

1/ Based on data for the Trojan Nuclear Powerplant. Adopted from: Equitable Environmental Health, 1976, p. 352.
2/ These residuals are released in an amount which allows the plant to operate in compliance with NRC design-objective dose-equivalent rates and, hence, which varies with subregion.
NA = Not Available.
Based on: University of Oklahoma, 1975, p. 6-1 to 6-74, except where otherwise noted.

(b) Coal-Fired Generation.

Technology

The coal for generating plants serving the BPA service area will generally come from surface mines in Wyoming and Eastern Montana. The generating plants may be located at the mines (mine-mouth plants), or be located at some suitable location closer to the loads they serve, in which case the coal must be transported to the plant. Coal transportation will generally be by unit trains, although slurry pipelines are a possibility. Mine-mouth plants require greater amounts of transmission facilities and suffer greater transmission losses in order to deliver power to loads than do plants near the load centers.

At the generating plant, the coal is pulverized and burned in a boiler to generate steam to power a turbine which, in turn, drives an electrical generator. Coal consumption of a 1000-MWe plant would average about 9000 tons per day over the course of a year, depending somewhat on the quality of the coal. Combustion of the coal produces a flue gas contaminated with several air pollutants which are treated by electrostatic precipitators, scrubbers, baghouses, or some combination of these. (Current standards for new coal-fired powerplants require removal of SO_2, even for low-sulfur coals, plus control of particulates.) Steam exhausted from the turbine must be condensed before it is returned to the boiler. This generally requires a cooling tower or pond to reject the heat to the environment although air cooling is a somewhat more expensive alternative. In addition, there is blowdown (i.e., water withdrawn to prevent buildup of contaminants) from the boiler and from cooling towers which requires treatment and disposal. Fly ash and slag, the solid residuals from combustion of the coal, and sludge from SO_2 scrubbers also require disposal.

Potential future technical developments for coal generation include use of fluidized bed combustion boilers which will have benefits from the standpoint of air pollution control, and improved technology for removal of SO_2 from flue gases.

Potential

Although there is very little coal within the BPA service area, total coal resources remaining in the ground in the 13 western states as of January 1, 1974, were estimated to be 2,730 billion short-tons. Of this amount, 1,023 billion short-tons are known and identified, and 1,707 billion short-tons are hypothetical resources. Surface-mineable reserves of subbituminous coal and lignite in western states were estimated by the Bureau of Mines at 87 billion tons.

A report of the Federal Energy Administration forecast the coal supply from mines in the western states to range from 250 million to 534 million tons annually by 1990. Even assuming a conservative recovery factor of 50 percent, surface-mineable reserves available from western states would be ample to supply the range of projected demands for many decades.

The location of coal deposits, the method by which the coal can be mined, the composition of the coal (such as sulfur content), and the heating value affect end-uses for the coal and determine the environmental impacts of its mining and use.

Coal production costs, costs of alternate fuels and energy sources, the ability to open new mines and obtain the necessary mining equipment, water rights, trained manpower, environmental impacts, and the legal and financial requirements necessary to develop coal resources are the factors limiting the availability of coal in the near future.

Additional constraints which limit the realistic potential for coal-fired generation are the availability of suitable sites, the ability to continue to meet ambient air quality standards, prevention of significant deterioration criteria to limit degradation of existing air quality, and potential rules to prevent visibility degradation by power plant plumes and other air pollution sources. The number of power plants which could be accomodated in spite of these constraints is unknown; however, studies indicate that a significant quantity of coal-based generation could be installed in the region and additional plants could also continue to be constructed outside the region while meeting all regulatory requirements.

Costs

The cost of coal for electricity production is determined by both the mining and transportation methods used to bring that coal to market. The most recent estimate of coal costs applicable to the Northwest are for coal from Gillette, Wyoming, to be delivered to the Boardman (Oregon) plant. This estimate is $7.25 per ton at the mine plus $14.59 per ton rail transportation (12.5 cents per ton per mile over 1,167 miles), or $21.84 total per ton. This estimate is for unit trains with utility ownership of the cars. (PNUCC Task Force 8). These costs are for coal containing 6.2 percent ash and 30 percent moisture, with a heating value of 8,200 Btu/lb. Higher ash and moisture contents and lower heating values will increase shipping requirements and overall costs. Coal transportation costs vary depending on annual tonnage volume, train and car size, types of equipment and terminal facilities, terrain and track conditions, and distance traveled.

The total busbar energy costs have been estimated for a hypothetical 500-MWe coal-fired powerplant within the BPA service region, varying by ownership, financing, and state. These costs range from a low of 19.2 mills/kWh for a Federally owned facility financed at 6.5 percent in 1976, to a high of 78.1 mills/kWh for a privately owned plant in Washington financed at 9.5 percent in 1995.

Environmental Impacts

Construction. Construction increases ambient pollution concentrations as a result of dust stirred up by vehicles and wind, and exhaust generated by diesel and gasoline powered equipment. Population increases induced by construction activity can further degrade the physical environment, plus result in adverse socioeconomic impacts in areas unprepared to cope with the transient construction population.

Noise impacts of construction can attain 64 dbA at 2600 feet and 60 dbA at 4000 feet distance.

Construction results in temporary increases in rates of air and water erosion and permanent removal of soils. Estimated localized erosion rates during plant construction may be as high as 5,000 ton/mile^2/year. Stream sedimentation and soil compaction may also occur.

Fuel Supply. Surface coal mining, predominant in the western states, has a number of adverse effects on the environment. Air residuals originate from the diesel-powered equipment used to dig and haul coal and overburden, and from dust due to wind erosion and vehicles. Reclamation and revegetation of mined areas and dust suppression practices can reduce the particulates generated by wind erosion and vehicles. Water pollution occurs from suspended solids produced by runoff from piles of overburden, but under controlled conditions coal pile drainage and runoff are collected and treated to reduce suspended solids to a concentration of 30 parts per million (ppm) and a zero acid content prior to discharge.

A typical area strip mine excavating 10,000 tons of coal per day produces 100 tons of solid waste per day which can eventually be used as fill in the reclamation process. Coal mining to support a 1,000-MWe plant would permanently disturb 251 acres and temporarily disturb 52 acres each year. Aquifers in mined areas may be permanently disrupted. Mining would displace existing land uses such as agriculture and grazing, although similar use can be made of reclaimed areas, since mining companies are required to reclaim mined lands by approximating the original topography and planting suitable vegetation. Nevertheless, the lands are irretrievably altered and the reclamation may not achieve the original productivity of the land. Opening new mines and expanding existing ones can result in significant influx of new population into remote areasuand can have significant socioeconomic impact.

Noise associated with surface mining orginates from drilling, blasting, and diesel equipment.

Since coal from the western states is relatively clean, it does not require washing. The breaking-and-sizing it requires results in noise and requires small amounts of water for dust control. In addition, land is required for both breaking-and-sizing and loading and storage facilities.

An estimated fixed commitment of 63 acres will be permanently disturbed as a result of coal processing operations associated with a 1,000-MWe plant. The processing operations would also generate approximately 220 tons of solid waste each year.

Coal can be transported from mine to generating plant by train, truck, or coal slurry pipeline. A 1,000-MWe plant would require about 9,000 tons of coal per day on the average. With old-style hopper cars carrying 55 tons each, 164 carloads must be delivered each day. With new unit train cars carrying 100 tons per car, 90 cars must be delivered.

Both truck and train hauling result in emissions from diesel fuel combustion and particulates due to wind losses. These particulate emissions during transportation have been estimated to be 2 percent of coal tonnage carried by conventional trains and 1 percent of tonnage carried by unit trains and trucks.

Coal slurry pipelines require large amounts of water. For example, Peabody Coal's Black Mesa slurry pipeline requires about 11 million gallons of water per 10^{12} Btu of coal carried (3,200 acre-feet per year). It also requires a 62.5-foot right-of-way along its length (7.58 acres per mile) and 50 acres for each of four pumping stations.

Coal stored in open piles at the mine, processing facilities, or generating plant can result in runoff containing sulfuric acid. Under controlled conditions this water is neutralized with lime or recycled and no significant quantities of residuals should occur.

Operation. The annual residuals resulting from operating a 1000-MWe coal-fired powerplant at an 80 percent capacity factor with a 38 percent conversion efficiency, are listed in Table IV-28 and are described below. (Plants do not usually operate at this capacity, but rather in the range of 65 to 75 percent. The 80 percent capacity factor provides an "upper-bound" estimate for impact calculations, but does not change impacts significantly. Also, 38 percent efficiency is 2 to 4 percent higher than the expected efficiency of a modern plant equipped with a scrubber to limit SO_2 emissions.)

Combustion of the coal in the generating plant results in air pollutants, principally particulates, sulfur dioxide, and nitrogen oxides. Air pollutants from coal-fired power plants can damage sensitive biota up to 50 miles downwind from plants, possibly resulting in decreased productivity, increased susceptibility to disease, and reduced reproductive potential.

TABLE IV-28

PACIFIC NORTHWEST 1,000-MWe COAL POWER GENERATION TRAJECTORY RESIDUALS

Residual	Extraction	Processing	Mine Mouth/-Load Center Transportation	Conversion	Total
Air Effluents (tons/year)					
Sulfurous	4.9	0	9.1 / 740	5,000	5,000 / 5,700
Nitrous	67.0	0	130.0 / 870	20,500 1	20,700 / 21,400
Hydrocarbons	6.7	0	13.0 / 570	500	520 / 1,100
Carbon Monoxid	41.0	0	76.0 / 810	1,700	1,800 / 2,600
Particulates	54.0	0	1,500.0 / 7,500	1,030 1/	2,600 / 8,600
Water Effluents (tons/year)					
Inorganics--	--	0	--	0	0
Suspended/-Dissolved Solids	0	0	--	360 2/	360
Organics	--	0	--	--	--
Solids (tons/year)	47,400	220	--	478,000	526,000
Thermal (10^9 Btu/year	NA	NA	NA	39,000	39,000
Land Disturbance					
Temporary (acres/year)	52	0	0 / 0	13	65 / 65
Permanent (acres)	251	63	19 / 2,400 3/	790	1,100 / 3,500
Water Consumption (acre-feet/year)					
To Air	NA	NA	--	11,500	11,500
To Water/Ground	NA	NA	--	6,900	6,900

NA = Not Available.

Based on: University of Oklahoma 1975, p. 1-1 to 1-131, except where otherwise footnoted.

1/ Based on standards for new coal plants published in the Federal Register, June 11, 1979, pp. 33580-33624.

2/ Based on Table V-62, p. V-285, Draft Role EIS.

3/ Varies with specific plant site.

Sulfur dioxide resulting from sulfur in the coal must be largely removed from combustion gases before discharge. A wet scrubber to perform this function could produce over 1200 tons of limestone sludge daily from a 1,000 MWe plant. This waste has no value, even for fill, and could leach into groundwater. Dry scrubbers now available produce a dry waste for which handling and disposal are easier. Combustion of coal also releases large amounts of carbon dioxide which is of concern since carbon dioxide buildup in the atmosphere may cause alterations in world climate. A 1,000 MWe coal plant with 97.5 percent precipitators was found to emit 10.8 millicuries of Radium 228 and 17.2 millicuries of Radium 226 per year, levels significantly below radiation protection standards.

A 1,000 MWe plant burning coal with a 10 percent ash content will also produce an average 900 tons of ash each day, nearly all of which comes out as slag from the boiler or which is captured by the air pollution control device as fly ash. Disposing of the ash is expensive and it has usually been dumped. New environmental regulations may require that it be returned to coal mines for disposal. Some fly ash may be usable in concrete.

The steam cycle results in periodic or continuous discharges of "blowdown" water containing chemicals to limit dissolved contaminants and remove impurities. This blowdown may be discharged into rivers, carrying chemicals.

The cooling cycle can impact local water conditions since it requires large amounts of water. Blowdown from cooling towers may also be discharged into rivers, carrying with it heat and chemicals. Fog enhancement can occur around cooling towers.

Health Effects

This discussion is an extraction of material from "The Environmental Effects of Using Coal for Generating Electricity," a report produced by Argonne National Laboratory for the U.S. Nuclear Regulatory Commission.

"Evaluation of the public health impact of a coal-fired electricity generating station is principally an assessment of the effects on human health. Most elements in coal, exclusive of carbon, are in the form of aluminosilicates, inorganic sulfides, and organize compounds. The organic compounds are decomposed to produce SO_2 and a number of oxides and other chemical species of varying volatility. The aluminosilicates, on the other hand, have very high vaporization temperatures, and therefore tend to survive more or less intact as flyash and slag. 1/ Combustion emissions are dependent on the type of coal, the process of combustion, and the efficiency and type of control devices. Estimation of dose from these airborne effluents requires knowledge of their chemical and physical nature and their interactions with the physical environment into which they are introduced."

A significant portion of the combustion products from coal is in the form of particulates. Particulates act as carriers of many trace elements and hydrocarbons in the effluent stream. Nickel (in the form of nickel carbonyl), chromium (especially in the form of chromic trioxide), beryllium, and arsenic have been implicated as carcinogens. In the organic particulates, many contain the known carcinogen benzo(a)pyrene and its relatives. Flourides, phenols and cresols, arsenic, selenium, nickel, chromium, and vanadium are all known to be highly toxic, with many exhibiting a special propensity for cellular deposition and retention. These elements are capable of interfering with and disrupting the function of the central nervous system and other organ systems of the body unrelated to the respiratory system. The consequences of inhalation of hydrocarbons are complex because the inhaled substances are always in mixtures. This intermingling of compounds makes it virtually impossible in field studies to incriminate any single material as the agent in the causation of pathologic changes. However, in experimental situations a number of organic compounds arising from the combustion or processing of coal have been identified as either known or "suspect" carcinogens, and others as strong eye and lung irritants.

Photochemical reaction products can be considered as secondary products of coal combustion. These compounds results from the interaction with ultraviolet radiation and the oxidation of effluent hydrocarbons. Aggravation of respiratory and cardiovascular illness, irritation of the respiratory tract, and impairment to cardiopulmonary function are health aspects related to photochemical oxidants exposure.

Nitrogen oxides (NO_x) are produced by both the oxidation of organically bound nitrogen in coal and the secondary oxidation of atmospheric nitrogen during the combustion of coal and most other hydrocarbons, especially at high temperatures and/or pressures. The two most important species are nitric oxide (NO) and nitrogen dioxide, also known as nitrogen peroxide (NO_2). Nitric oxide is an unstable species which oxidizes readily to NO_2. Nitrogen oxides are also important in the generation and regulation of ozone levels and in the production of organic components of photochemical smog. The species most commonly found in the atmosphere is NO_2 which is a strong irritant.

Carbon monoxide (CO) may be produced during incomplete combustion of coal, and is therefore most likely to appear when a concerted effort is being made to control NO_x emissions. CO is best known for its affinity for hemoglobin, with which it combines to form carboxyhemaglobin (COHb), which has a very long residence time in blood. At COHb levels greater than 1.3 percent in blood for over 8 hours, persons with stable coronary artery disease (angina pectoris) may start to note increased frequency and duration of symptons; at blood levels of 1.9 percent, excess deaths may occur among people with preexisting cardiovascular disease.

In some studies, SO_2 has been found to interact with other irritants to both enhance and ameliorate their effects. An experimental subject habituated to sulfur dioxide, for example, will not react as strongly to a subsequent dose of nitrogen dioxide as one without such prior exposure. Indications of a synergism have been found in studies involving ozone (O_3) and histamine wherein prior exposure to SO_2 will result in more severe reactions to those irritants. It has not been shown to produce serious direct effects in the pure state in humans in the concentrations which would ordinarily be expected in areas of heavy coal utilization (i.e., 0.3 to 1.5 ppm), although levels above 0.25 ppm are usually associated with adverse health effects in epidemiological studies.

Health effects analysis is basically a matter of determining dose and estimating response. Physiological and pathological responses of the population exposed to the airborne insults from coal will reflect the individual's ability to respond and the duration or history of exposure. There will always be individuals who have severe short-term reactions to any increased level of a contaminant. Subgroups such as young children, the aged, and the infirm are more sensitive to the impact of increased concentrations of respiratory irritants and other poisons.

The short-term adverse effects from coal combustion will be manifest in these subgroups as an increased incidence of respiratory disease, asthma, aggravation of preexisting chronic cardiopulmonary disease, and premature death. Chronic exposure to coal combustion effluents may result in an increased incidence of respiratory diseases and cancer in the total population.

All chemical agents cause some form of biological response. The response is usually related to the quantity absorbed and the period of time over which such absorption occurs. One belief is generally accepted; the slight deviations in physiological parameters that remain within homeostatic limits, but which result from very low-level exposures to environmental stressors, are not categorically deleterious. This reasoning underlies the threshold concept. The threshold dose or "zero effect" level, is that quantity of a specified agent that an organism is able to metabolize, detoxify, or excrete without harmful biological consequences.

In any population, the threshold for response to airborne contaminants is not the same for all individuals. Whilte the main concern of an analysis of population risk is apparently with the average individual, it is important to recognize the existence of high risk groups in which many of the observed responses will occur. The risk factors of age, preexisting illness, genetic sensitivity, occupation, and personal habits (such as smoking) define the hypersusceptible individuals who are more sensitive than most to changes in ambient air quality. These individuals may exhibit severe responses to air contaminants that are below the threshold level of the majority of the population.

The difficulties in accurately predicting population responses from experimental animal data result from the complicated relation between ambient air pollution and related health effects in humans. Estimation of the dose term from a single point source must consider source emission rate along with atmospheric transport parameters that further specify the potential delivered dose. Only after ambient concentrations at the receptor site have been carefully established can an accurate dose evaluation be made.

Risk-benefit analysis attempts to equate the beneficial societal consequences of a specific activity, such as operation of a coal-fired power plant, with the associated probable costs in terms of human health. Given a reasonable estimate of the hazard posed by environmental contaminants and combustion effluents, the magnitude of risk can be estimated. However, quantitative extrapolation from predictor systems to the exposed population is often uncertain, and second, the criteria for defining acceptable versus unacceptable risks is often unclear. 1/

Refer to Table IV-29 for a summary of the discussion.

Footnotes

1/ The Environmental Effects of Using Coal for Generating Electricity, report prepared by Argonne National Laboratory for the Division of Site Safety and Environmental Analysis, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, completed May 1977 and published June 1977.

TABLE IV-29

AIR POLLUTANTS AND ASSOCIATED RESPIRATORY HEALTH EFFECTS 1/

Major Pollutants	Principal Respiratory Effect of Inhalation (known or suspected)
Total Suspended Particulates	Directly toxic effects or aggravation of the effects of gaseous pollutants, especially SO_x; aggravation of asthma or other respiratory or cardiorespiratory symptoms; increased cough and chest discomfort; increased mortality.
Carbon Monoxide	Aggravation of coronary artery diseases, premature dealth of cardiovascular diseased.
Oxides of Sulfur	Aggravation of respiratory diseases, including asthma, chronic bronchitis, and emphysema; reduced lung function; irritation of respiratory tract; and increased mortality.
Hydrocarbons	Cancer, strong eye and lung irritant.
Arsenic	Bronchitis and other respiratory illnesses.
Barium	Nose and throat irritation.
Beryllium	Acute and chronic respiratory disorder from short-term exposure.
Chromium	Lesions of respiratory mucous membranes.
Fluorides	Irritation of respiratory tract and respiratory impairment.
Nickel Carbonyl	Possible cause of asthma.
Phenols and Cresols	Corrosion of mucous membranes of nasal and respiratory tract.
Selenium	Respiratory irritation.
Vanadium	Acute respiratory irritation.

(This table was developed from information in Energy from the West: Impact Analysis prepared for the Environmental Protection Agency, 1979.)

SO_x oxides of sulfur

1/ Kash, Don E., et. al. Impacts of Accelerated Coal Utilization, Report submitted to the Office of Technology Assessment. Norman, Oklahoma: University of Oklahoma, Science and Public Policy Program, 1977, p. 8-1. Adapted from U.S., Council on Environmental Quality. Environmental Quality, Sixth Annual Report. Washington, D.C.: Government Printing Office, 1975.

(c) Combustion Turbines.

Technology

In combustion turbines, outside air passes through a rotary compressor into the combustion chamber where a fuel is injected and burned. The hot combustion gases flow through the turbine blades connected to a shaft which simultaneously drives the turbine, air compressor, and electrical generator. The gases may then be exhausted through a muffling system to the atmosphere.

Combustion turbines generally burn natural gas or oil. They could also use gaseous and liquid synthetic fuels derived from coal, oil shale, or biomass.

Because combustion turbines utilize comparatively expensive fuels, their operating costs are generally high and they generally operate with low load factors, serving peaking and standby needs.

The efficiency of combustion turbines can be increased by routing the exhaust gases to a waste heat boiler to produce steam to provide additional power to the generator. Such an arrangement is called a combined-cycle system. Because of the time required to heat the boiler and steam turbine, the steam cycle portion of such a unit cannot be used to meet short-term peak loads, but it would provide additional capacity during longer periods of high loads such as might occur during a severe winter storm.

Potential

The potential of combustion turbines depends primarily on the availability of fuel. The National Energy Act prohibits the use of oil or natural gas in new electric utility generating facilities unless an exemption is granted on the grounds that an oil or gas-fired plant is substantially less expensive over a given period of time than a plant fired with an alternate fuel. It may be difficult to secure such exemptions for new combustion turbine generating plants, especially if operation at relatively high capacity factors is envisioned.

Cost

The estimated capital cost for a turbine using No. 2 oil, starting operation in 1985, is $230/kW, plus $10/kW for oil storage facilities for a 30 day supply of oil. Operated as a peaking unit with a 15 percent capacity factor, such a combustion turbine would have a total annual cost of $120/kW (91 mills/kWh). The total annual cost of the same plant operated as a base-load resource at 75 percent capacity would be $470/kW (72 mills/kWh).

The estimated capital cost of a No. 2 oil-fired combined-cycle system, starting operation in 1985, is \$480/kW plus \$30/kW for oil storage facilities for a 30 day supply. (It is assumed that the capacity factor for a combined-cycle plant will be higher, so that larger oil storage facilities are required.) The annual cost of the system would be \$130 kW at 15 percent capacity (99 mills/-kWh) and \$400 kW at 75 percent capacity (61 mills/kWh).

The costs incurred with combustion turbines or combined-cycle systems using fuels other than No. 2 oil would be comparable or, where the fuel is cleaner or need not be stored, somewhat lower.

Environmental Impacts

Combustion turbines and generators are manufactured items. Impacts of the manufacture of these items are presumed to be typical of manufacturing facilities. At the site, access roads, transmission lines, fuel storage and treatment facilities, and a building to house the turbine-generators must be constructed. Impacts of this construction are similar to other construction activities, but are less than for coal or nuclear plants because of the scale of the project.

Production of gas and oil has significant environmental impacts on a global scale, although only a small fraction of these impacts can be attributed to the use or potential use of combustion turbines in the region. Impacts include air quality degradation from extracting, refining, transporting, and storing oil, and extracting and shipping natural gas; water quality impacts from offshore drilling, oil spills, and refining; impacts on aquatic life and wildlife from oil spills; and many others. The reader is referred to "Energy Alternatives: A Comparative Analysis" 1/ for information concerning the environmental impacts of supplying gas and oil products.

The operational impacts of combustion turbines principally affect air quality and noise levels. The Environmental Protection Agency (EPA) has estimated emissions from turbines based on a typical operating cycle, typical turbine unit, and under typical conditions. This data is given in Table IV-30. The emissions most difficult to control and emitted in greatest quantity are nitrogen oxides, resulting from the high peak temperatures in the combustion chamber. On September 10, 1979, EPA promulgated emission standards for new stationary gas turbine generators greater than about 1 MW capacity. 2/ These limit emissions of nitrogen oxides and sulfur oxides. Oil storage and handling results in some additonal emissions of hydrocarbons.

Noise levels of the PGE Beaver Generating Turbines are stated as being less than 50 dB(A) at 800 feet and 44 dB(A) at 1500 feet. 3/ Sound levels of 64 dB(A) to 49 dB(A) at 400 feet are advertised by one manufacturer, for simple single-cycle units with sound

TABLE IV-30

COMPOSITE EMISSION FACTORS -
ELECTRIC UTILITY TURBINES

Time Basis	Nitrogen Oxides	Hydrocarbon	Carbon Monoxide	Particulate	Sulfur Oxides
Entire population					
lb/hr rated load 1/	8.84	0.79	2.18	0.52	0.33
kg/hr rated load	4.01	0.36	0.99	0.24	0.15
Gas-fired only					
lb/hr rated load	7.81	0.79	2.18	0.27	0.15
lb/hr rated load	3.54	0.36	0.99	0.12	0.044
Oil-fired only					
lb/hr rated load	9.60	0.79	2.18	0.71	0.50
kg/hr rated load	4.35	0.36	0.99	0.32	0.23
Fuel Basis					
Gas-fired only					
$lb/10^6\ ft^3$ gas	413	42	115	14	940 S 2/
$kg/10^6\ m^3$ gas	6,615	673	1,842	224	15,000 S
Oil-fired only					
$lb/10^3$ gal oil	67.8	5.57	15.4	5.0	140 S
$kg/10^3$ liter oil	8.13	0.668	1.85	0.60	16.8 S

1/ Rated load expressed on megawatts.
2/ S is the percentage sulfur. Example: If the factor is 940 and the sulfur content is 0.01 percent, the sulfur oxides emitted would be 940 times 0.01, or 9.4 $lb/10^6\ ft^3$ gas.

Source: U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Third Edition, August 1977.

reducing devices installed. 4/ Without sound deadening devices, the sound level of four 250 MW turbines operating at capacity at 1200 feet would be 65 to 70 decibels. Sound deadening would normally be required.

A 1,000 MW combustion turbine plant would require about 100 acres.

Simple-cycle combustion turbines have no impact on water supply or quality unless they use water or steam injection for control of air pollutant emissions. Water or steam injection requires a supply of demineralized water and produces a waste stream containing the minerals removed from the water which requires disposal. Treatment of fuel oil to remove minerals can also result in additional water consumption and pollutants.

Combined cycle units have additional requirements both for demineralized water for use in the steam cycle, and for makeup water for cooling towers or ponds. They will also have boiler and cooling tower blowdown as in other steam cycles.

Footnotes

1/ The Science and Public Policy Program, Energy Alternatives: A Comparative Analysis, Prepared for the Council on Environmental Quality and Others, May 1975.

2/ Federal Register, Vol. 44, No. 176, September 10, 1979, p. 52792-52807.

3/ Rom, W. J., and Russell, D. S., Ebasco Services, Inc., "Pacemakers/Beaver: Designing for Fuels Flexibility" in 1979 Generation Planbook, p. 50-54.

4/ General Electric Gas Turbine Division, Sales Brochure No. GEA 9680C, General Electric Heavy Duty 7001 Gas Turbines.

(2) Unconventional Resources.

(a) Synthetic Fuels.

"Synthetic Fuels" refers generically to replacement fuels for petroleum products and natural gas. They are derived principally from the domestic sources of coal, oil shale, and biomass.

1. Coal-Derived Fuels.

Two processes are currently employed to produce synthetic fuels from coal: gasification and liquefaction. Gasification results in low and intermediate Btu gases (100 - 400 Btu/ft^3), high Btu gas (900 Btu/ft^3), and methanol fuel. Liquefaction produces synthetic crude oil. Since the environmental impacts of all coal based synthetic fuels are similar, they are discussed at the end of the following discussion.

a. Gasification.

Current advanced gasification schemes for electrical generation feature combined cycle systems which are more efficient than conventional coal fired boiler plants with stack gas scrubbers.

Low and Intermediate Btu Gas

Technology. Low and intermediate Btu gas production technology is well developed and is in use commercially outside the U.S. Basically, the conversion occurs as a result of exposure of coal to steam, air, oxygen, hydrogen, or some combination of these gases under high temperature conditions. Three physical configurations are used to carry out the reaction:

moving grates which support coal through which the reactant gases are passed;

fluidized beds in which the bed surface area is enlarged, allowing more surface contact by suspending coal particles in a countercurrent stream of the reactant gas; and

entrained flow in which coal particles are suspended in the reactant gas flowing cocurrently through the reactor.

Potential. Commercial plants are in the initial stages of development and are not expected to be on-stream contributing to the national energy supply prior to the mid to late 1980's.

Costs. Average gas product costs and capital costs are shown below in mid-1975 dollars: 1/

Technology	Capital Costs, $/KW*	Energy Costs at 70% Capacity Factor	
		$/106 Btu	mills/kWh
Moving Bed	652	3.78	34.0
Fluidized Bed	426	2.69	24.2
Entrained Flow	376	2.48	22.3

* Combined coal gasification plant and rankine cycle generating plant with additional generation from a bottoming cycle to recover waste heat from the gasifier.

High Btu Gas.

Technology. High Btu or synthetic natural gas can be substituted directly for natural gas. Consequently, its commercial development has received more attention.

Potential. Although the technology for such plants exist, there are no commercial plants operating at this time.

Costs. Plant capital costs are estimated to be between $377 million and $594 million for a plant producing 250 million ft^3/day of gas product. 2/ Gas product costs are estimated to be $2.47 to $3.92/$10^6$ ft^3 in 1975 dollars.

Methanol.

Technology. Methanol fuel is a low grade methanol that contains longer chain alcohols and hydrocarbon materials. It is produced by a gasification/synthesis reaction process, and can be purified to methanol at additional cost.

Potential. Presently there are no commercial plants in the U.S.

Costs. Recent cost studies 3/ 4/ predict production costs of methanol fuel as low as 18.8[/gal. ($3.00/$10^6$ Btu) while reported costs of methanol derived from coal range from 20.8[to 60[/gal. in 1977 dollars. Capital costs for a plant consuming 74,000 ton/day of coal to produce 17.43 x 10^6 gallons/day of methanol fuel/methanol were estimated to be $3.1 billion with a 5-year construction period.

b. Liquefaction.

Technology. Coal liquefaction, while having received less attention than coal gasification, offers several important advantages. Less chemical change is required to produce a liquid from coal, conversion efficiency is higher, and less time is required for commercial implementation due to the use of well-developed materials and equipment components. There are two basic liquefaction processes: carbonization to thermally crack coal; and hydrogeneration for dissolution of coal either directly, via a solvent, or via a synthesis reaction following coal gasification.

Potential. Presently there are no commercial plants in the U.S.

Costs. Estimated coal costs for leading technologies 5/ show the range in investment costs based on plant capacity of 50,000 bbl/day, and in 1975 dollars to be $40.08 to $46.40/bbl of coal liquid produced per day. The production price of synthetic oil would average $22.08/bbl in 1975 dollars.

Impacts of Coal-Derived Fuels. The environmental impacts of mining, processing, and transporting coal are discussed in the section on coal generation.

Gasification plants are environmentally advantageous as they can be modified to meet any required level of sulfur emission, emit no particulates, and emit lower levels of nitrogen oxides. They require 1-1/2 to 3 pounds of water for each pound of coal processed. This is approximately twice the requirement for an electric power plant with the same energy output. Large amounts of solid waste will be generated for disposal. The coal needs of a typical plant will require the mining of approximately 400 acres of land per year. Irrigation is necessary for land reclamation in arid areas. In addition, the high temperatures used in gasification processes produce molecules of polycyclic aromatic hydrocarbons which are carcinogenic. Workers exposed to these compounds reportedly have a higher than normal probability of developing skin cancer. The same materials are produced in coal liquefaction and oil shale retorting.

The use of methanol as a replacement for conventional gasoline and other petroleum-based fuel can reduce emissions of carbon monoxide, nitrogen oxides, and lead, but would increase emissions of aldehydes.

2. Oil Shale Fuels.

Technology. Nonconventional sources of oil for synthetic fuels include oil shale, tar sands, and heavy oil. Technological development has generally proceeded more slowly than for coal gasification, especially in the U.S. Tar sands operations are being conducted on a large scale of 100,000 bbl of oil per day in Canada. The tar sands are surface mined and produce one barrel of oil for each two and one half tons of tar sands mined. The residual material must be returned to the mine pit.

To obtain oil from oil shale, a solid organic consitituent of the shale, kerogen, must be removed by a heating process to produce both liquid and gaseous products. The liquid may next be upgraded using conventional petroleum refining techniques. The gases produced vary significantly depending on the particular heating process: 80 Btu/ft^3 for direct internal combustion to 800 Btu/ft^3 for indirect heating.

Potential. In the U.S., the potential is good for the development of an oil shale industry by the mid to late 1980's. The major high grade oil shale deposits are located in the Green River Formation which underlies approximately 16,500 square miles in the states of Colorado, Utah, and Wyoming. There are an estimated 800 billion barrels of oil ultimately recoverable, but only about 80 billion barrels can be obtained with current technology. 6/

Costs. Production economics depend extensively on the grade of oil shale being utilized. Plant costs average $36.5 million for high grade shale. The product oil cost range is $10.90/bbl for high grade shale to $28.00/bbl for low grade shale in 1975 dollars. 7/ Production costs for the oil were approximately $15 to $20/bbl in 1978.

Environmental Impacts. Oil shale surface and underground mining techniques are similar to those used in coal mining. However, since even the highest grade of raw oil shale contains only about 30 gallons of oil per ton, the large volume of spent shale presents an additional disposal problem and must in most cases be returned to the mine. Environmental impacts of production of oil from oil shale are dependent on the process used, but they include degradation of air quality; water consumption; commitment of land to use for the plant and for waste disposal; and the socioeconomic effects of developing major energy facilities in relatively undeveloped and sparsely populated areas. Residuals of oil shale development are shown in Table IV-31. 8/

TABLE IV-31

RESIDUALS FROM OIL SHALE MINING AND PROCESSING

Residual	Mining	Production
Land	0.87-4.72 acres/10^{12} Btu	3.1 acres to 230 acres
Water Use	2.3-3.3 acre-ft/10^{12} Btu	56.9-102 acre-ft/10^{12} Btu
Air Pollutants		
Particulate	4.26-20.79 tons/10^{12} Btu	29.6-51.3 tons/10^{12} Btu
SO_2	0.014-0.21 tons/10^{12} Btu	6.21-102.7 tons/10^{12} Btu
NO_x	0.10-2.8 tons/10^{12} Btu	11.4-33.7 tons/10^{12} Btu
Hydrocarbons	0.16-0.33 tons/10^{12} Btu	0.51-10.5 tons/10^{12} Btu
CO	0.02-1.7 tons/10^{12} Btu	10-25 tons/10^{12} Btu
Water Pollutants	None discharged to surface waters	None discharged to surface waters
Solid Waste	Negligible, waste used as fill in mine reclamation	109,000-210,000 tons/10^{12} Btu

3. Biomass Fuels.

Technology

Synthetic fuels can be derived from biomass sources by a variety of processes. In most cases, the technology is not well developed, since direct firing of the organic materials has received the major emphasis to date.

Biomass-derived fuels with near-term potential include liquid alcohols (methanol and ethanol) and gaseous methane from animal waste sources. The latter is oriented toward energy displacement in small scale farming operations. Anerobic digestion facilitates bacterial conversion of organic materials into methane gas. Methanol is produced from biomass by the pyrolysis of cellulosic materials. Ethanol is produced by the bacterial conversion of carbohydrates.

Potential

Alcohol production has received a great amount of attention due to its potential for replacement of petroleum products as a fuel for both transportation and peak electrical generation. At the present time, ethanol is produced commercially in the U.S., but there is almost no methanol production from either biomass or fossil sources. Regional availability of the resources are discussed in the sections on wood and municipal waste.

Costs

Demonstration projects are in operation, but actual cost estimates depend substantially on project scale. Estimates of plant costs for the production of 65 million gallons of alcohol per year are approximately $64 million for methanol 9/ and $126 million for ethanol. Estimated fuel production costs are $\$16.50/10^6$ Btu for ethanol and $\$9$-$10^6$ Btu for methanol in 1976 dollars. 10/

Environmental Impacts

The impacts of the raw material supply associated with the use of biomass for synthetic fuels are essentially the same as the fuel supply impacts discussed in the sections on wood and municipal waste. Pyrolytic conversion processes result in sludge or char which require disposal, emission of air pollutants including methyl chloride from the pyrolysis of plastics in municipal waste, and water which must be treated and either recycled to the process or discharged. Quantitative data on residuals is not generally available.

Footnotes

1/ Gluckman, M. J., "The Status of Coal Gasification for Electric Power Generation." A paper presented at Session 22 of the 1976 joint Power Generation Conference, September 22, 1976, Buffalo, New York. Cost estimates prepared by the Fluor Engineers and Constructors, Incorporated.

2/ Electrical Power Research Institute (EPRI), "Fuel and Energy Price Forcasts," EPRI EA-411, Final Report, March 1977. Cost estimates prepared by the U.S. Bureau of Mines, Process Evaluation Group Studies.

3/ U.S. Department of Energy, "Conceptual Design of a Coal to Methanol Commercial Plant," Interim Final Report, July 16, 1976 February 15, 1978. Prepared by Badger Plants, Incorporated.

4/ U.S. Department of Energy, "The Report of the Alcohol Fuels Policy Review," June 1979.

5/ EPRI 1977, op cit Vol II, p. 136.

6/ Environmental Protection Agency. "Oil Shale and the Environment," EPA - 600/9-77-033, October 1977.

7/ Electric Power Research Institute, "Fuel and Energy Price Forecasts," EPRI EA - 433, Final Report, February 1977. Cost estimates prepared by the Oil Shale Corporation.

8/ The MITRE Corporation, Environmental Data for Energy Technology Policy Analysis, Vol. 1: Summary, prepared for U.S. DOE, January 1979.

9/ Lipinsky, E. S., et. al., Fuels From Sugar Crops, 1976, BMI 1957, 1957, Battelle Columbus Laboratories, Columbus, Ohio.

10/ U.S. Department of Energy, "Biomass-Based Alcohol Fuels: The Near-Term Potential for Use with Gasoline," August 1978, HCP/T4 101-03.

(b) Municipal Waste Combustion.

Technology

Until recently, large-scale harnessing of municipal waste for energy has been confined to European countries. The emergence of full-scale refuse-energy systems in the United States during the past few years has primarily been limited to two general areas: (1) refuse-fired steam-generating systems delivering lowor moderate-pressure steam to nearby industrial plants; and (2) a few pilot plant applications using shredded paper and light plastic refuse as fuel. The shredded material is either fired as a 10 to 20 percent (heat value) supplement to coal in a modified boiler or converted to gas or oil in a destructive distillation process, called pyrolysis. The production of gas and oil from municipal waste is discussed in the section on Synthetic Fuels. Other combustible waste, such as wood waste or agricultural waste, can be burned with the municipal waste if desired.

Direct combustion is the most likely near-term method of extracting energy from municipal waste. This is accomplished by combustion on moving-grates using 100 percent refuse (at optimum temperature for steam generation), or suspension firing of air-classified, shredded refuse (usually burned as a supplemental fuel in a coal-fired boiler).

The moving-grate system developed over the past two decades has demonstrated reliable performance in producing high-temperature steam. It consists of a refuse-fired, steam-generating boiler equipped with reciprocating grates arranged in steps over which the burning refuse tumbles to provide complete combustion. Air is introduced under and over the grates, raising the firing temperatures and producing gases at 800 to 1000°C. Boiler tubes in the furnace walls and convection section produce superheated steam for driving a turbine generator. 1/

Suspension firing of refuse, as a supplement to pulverized coal, has been successfully demonstrated and might prove worthwhile where the needed modifications to existing fossil-fuel boilers are economically justified. In such a system, refuse is passed through one or more large shredders and ferrous material is extracted with a magnetic separator. The remaining material is conveyed to a classifier where a forced-air current separates the particles into light and heavy components. The lighter fraction (primarily paper and plastic) can be blown into a utility boiler, typically as a 15 percent fuel supplement to the pulverized coal introduced through separate burners. 1/

Chief advantages of the boiler fired with unprocessed waste are the demonstrated relibability of mature technology, good efficiency, and low operating cost. Its main disadvantage is the high initial capital expenditure required, but this is largely offset by low-cost operation. The shredded-refuse system allows existing high-temperature, high-pressure utility boilers to be directly supplemented with air-classified trash. Initial costs for boiler modifications are lower, but usually total operating cost is higher and service life is shorter than with a boiler fired with unprocessed refuse.

Potential

Municipal waste production ranges from 3 to 5 lbs per person per day. 2/ 3/ Using 3.4 lbs per person per day and future population projections, 15,160 tons per day of municipal waste will be available in urban areas of the Northwest in 1987. 2/ Assuming a heating value of 5500 Btu/lb of refuse-derived fuel (RDF), a 20 percent weight loss during RDF processing, 20 percent conversion efficiency and a 65 percent capacity factor, this would translate into approximately 500 MWe of capacity. However, this is spread over a very wide area and long transportation distances make it impractical to consider large-scale plants. The largest waste generation centers are the Seattle, Washington, and Portland, Oregon, areas which could sustain 190 MWe and 105 MWe plants respectively in 1987 if the estimates on population and waste production rates given above prove correct.

The largest incentive for incinerating municipal waste is not so much for the energy generated as it is for the reduction of the disposal problem.

Costs

Cost studies for municipal waste-fired generation are generally directed towards determining a waste disposal cost rather than an energy cost. The cost and production figures presented here were extrapolated from site-specific studies and could vary for a site with unique problems or opportunities.

Cost and production data for a 207 ton/day municipal waste-fired electrical generating production plant which could handle all municipal waste from a city of between 80,000 and 135,000 people are as follows (1976 dollars): 4/

Capital Cost	\$10,580,000
Annual Cost (Capital ad Operating)	\$ 2,067,000
Capacity	10 MWe
Electrical Energy	60×10^6 kWh/year
Conversion Efficiency	20%
Bus Bar Energy Cost	35 mills/kWh
Net Waste Disposal Cost	\$18.90/ton

The net disposal cost of the municipal solid waste reflects revenues of 7.5 mills/kWh for the electricity generated. As the revenues increased, disposal costs would be reduced. The range of municipal waste disposal costs by conventional means presently is $2 to $12 per ton. Costs of new conventional disposal facilities such as landfills are projected to be double the existing disposal costs. 5/

Environmental Impacts

Impacts of fabrication and construction include those from the production of steel, concrete, and other materials for the plant; the manufacture of components such as the boiler, generator, refuse processing equipment, etc.; and the dust, noise, vehicular emissions, and loss of plant and animal life on the site which are typical of construction activities.

Operation of municipal waste-fired power-plants will reduce the future requirements for sanitary landfills by as much as 95 percent. They will also enhance the probability of recycling glass and metals in the waste, which will reduce the impacts of producing these materials from virgin resources and will result in greater availability of these materials for future generations.

Major residuals associated with burning of refuse are atmospheric emissions and heat dissipated through cooling water or cooling towers. Water containing a high biochemical oxygen demand would require treatment. This may be done on-site, or the water may be sent to a sewage treatment plant. Stack gases require scrubbing for particulate removal in all cases, and solid residues require disposal in landfills. Char quantities range from 0.07 to 0.1 ton per ton of raw refuse or 6,000 to 9,000 tons of char per 10^{12} Btu's input to the process. 1/

The environmental impacts of solid waste-fired steam and electric generating plants are as follows: 4/

Land Requirement	$1.72(10)^{-5}$ Acre-Yr/10^6 Btu
Water Requirement	0.012 Acre-ft/10^6 Btu
Air Emissions	(Lbs/106 Btu of input)
NO_x	0.150
SO_2	0.384
Particulate	0.320
Water Pollutants	
HCl	0.100
Other	0.034

Unfortunately, the potential for municipal waste-fired powerplants is greatest in urban areas, and these areas are often not in compliance with existing air quality requirements. This will constrain the development of municipal waste as an energy resource.

Footnotes

1/ BPA Draft Role EIS, Part 1, p. V-135 to V-142.

2/ W. H. Carlson, Municipal Solid Waste Utilization, WPPSS Advanced Energy Program, Feb. 1972, p. 2730.

3/ CH2M Hill, Market Analysis of Recovered Materials and Energy from Solid Waste, Jan. 1977, p. 5-2.

4/ L. R. Johnson, et. al., Northwest Energy Policy Project Study Module III B, Unconventional Energy Sources, 1977, p. 134-150.

5/ Metropolitan Service District, Disposal Siting Alternatives, Summary, Sept. 1978, p.

3. Impacts of Future Regional Resource Scenarios.

a. Introduction.

The following scenarios of future power resources are based on regional electrical loads through 1998 as projected by the PNUCC for the West Group Area of the Northwest Power Pool, as shown in Table IV-32. Energy loads used are taken from the "Econometric Model - Electricity Sales Forecast" dated March 1979. Peak loads are those included in the "Long-Range Projection of Loads and Resources for Resource Planning" (the "Blue Book"), dated April 23, 1979.

Six resource scenarios to meet these projected loads are evaluated in this section. Three are based on renewable resources and conservation. Scenario A assumes that all load growth through 1998 not met by existing conservation and other energy resources under construction is met through the development of centralized renewable generation, without any additional conservation beyond existing measures. Scenario B assumes maximum conservation, including the use of mandatory measures, with any remaining loads met through end-use renewable resource development. In addition, the NRDC Alternative Scenario is included at the end of this section. This scenario differs from the other scenarios in that it was developed by NRDC independent of BPA's scenarios, and in that it is based on assumed policies by regional entities to achieve reduced levels of energy use, rather than the technical potential of the technologies which were used in BPA's scenarios.

The other three scenarios project the development of conventional resources (large-scale coal and nuclear thermal plants) to meet regional loads. Scenario C assumes that energy loads are met primarily through construction of coal-fired baseload plants. Scenario D assumes that nuclear plants, rather than coal-fired plants, provide baseload generation. Finally, Scenario E assumes a mixture of coal and nuclear baseload generation similar to the mixture of resources which developed under the Hydro-Thermal Power Program.

All five BPA scenarios are designed to provide sufficient resources to meet energy loads as projected by the mean forecast of the PNUCC econometric model. The NRDC Scenario is based on a different load projection from the one in Table IV-32. In that other rates of load growth are possible, Table IV-32 also provides load estimates for two higher and two lower rates of load growth. The alternate growth rates are not applied to the resource scenarios that follow; however, given the information provided, it is possible for the reader to construct variations on the scenarios which are based on higher or lower rates of load growth.

Tables IV-33 and IV-34 present, respectively, net energy and peak resource requirements for the BPA scenarios. The NRDC Scenario did not address the issue of peak resource requirements. The values in these tables were obtained by subtracting the projected resources in Table IV-32 from projected requirements in the same table. Then, net resources required were adjusted according to whether resources not yet approved for construction were consistent with the assumed direction of each scenario. Thus, 1998 energy requirements for Scenario C in Table IV-33 (11,856 average megawatts) are the difference between the mean forecast of 1998 energy requirements (31,120 average megawatts) and 1998 energy resources (23,086 average megawatts) as shown in Table IV-32 (for a difference of 8,034 average megawatts), with an adjustment for nuclear plants not yet approved for construction (Pebble Springs 1 and 2 and Columbia 1 and 2) which are not consistent with the scenario's assumption of 100 percent coal-fired generation (adding 3,822 average megawatts to the amount of resources needed, for a total of 11,858 average megawatts, the figure shown as 1998 requirements under Scenario C on Table IV-33).

The net values in Tables IV-33 and IV-34 assume that all of the resources currently in process of development, with exceptions as explained below, are completed on schedule according to the PNUCC "Long-Range Projection of Loads and Resources for Resource Planning." Six generating plants (Colstrip coal-fired units 3 and 4, Pebble Springs nuclear plants 1 and 2, and Columbia nuclear plants 1 and 2) have not yet received full certification for construction; these plants are included or omitted from the scenarios consistent with the resource assumptions of each individual scenario. Specifically, all six plants are omitted as resources in Scenarios A and B, the Pebble Springs and Columbia plants are omitted in Scenario C, the Colstrip generators are omitted in Scenario D, and all six plants are included as resources in Scenario E. Wherever any of these plants are included in a scenario, their impacts are considered to be part of the total impacts of the scenario.

The BPA scenarios are in no way intended to be predictions of the future development of the Pacific Northwest power supply system. Rather, their purpose is to indiciate potential "extreme-case" patterns of development in terms of environmental effects. As such, they are strictly hypothetical. Actual development of the regional power system will be based on the application and outcome of existing and developing regional planning processes, as well as technological developments which cannot be anticipated. These processes, as defined by the proposal and alternatives, are described in the discussions of "Power Planning" and "Sources of Power" included in Chapter III. The NRDC Scenario, however, is intended to illustrate a possible future, assuming policymakers at the different levels of regional government adopt policies and provide incentives to achieve the assumed levels of saturation of load-reducing measures.

Although the BPA scenarios have been characterized as "worst-case" projections of regional power resource development, they are worst-case only in the sense that they represent extremes of reliance on a given type of technology. In the renewable energy scenarios, Scenario A relies on renewable forms of centralized electrical generation, whereas Scenario B relies instead on end-use renewable energy to displace electrical loads. In the conventional energy scenarios, Scenario C relies on coal-fired generation for baseload energy, Scenario D on nuclear generation, and Scenario E on a combination of coal and nuclear generation; all three scenarios are based upon centralized generation of electricity and transmission via the regional high-voltage grid to loads throughout the region. Given these basic orientations for the scenarios, resources were projected for the region based on rational considerations relevant to resource planning, for example, balancing peak and energy resources to meet both energy and peak loads without large surpluses of either, without deliberately selecting a more environmentally harmful resource simply to amplify the worst-case impacts. Where information was lacking, assumptions were made which were intended to be realistic, but which, if in error, would err in the direction of greater rather than lesser impacts. Many such assumptions were necessary, particularly for technologies which are still under development.

The scenarios presented here are conjectural and have been designed in an attempt to overcome the limitations of the information which is currently available. The process of developing these scenarios cannot substitute for the formal processes which will occur in actual resource planning.

None of the BPA scenarios as presented below can be considered a likely outcome of regional resource development, due mainly to the extreme reliance each scenario places on a particular type of resource. A far more probable pattern of development would consist of a mixture of conservation, end-use energy, renewable generation, and conventional thermal resources. In that it is not possible to predict the mixture which would actually develop out of a virtually infinite number of possible combinations, and also because such a mixture would not portray worst-case impacts, no such scenario was included in this analysis.

The NRDC Scenario is portrayed as a possible result of regional energy policy, however, its authors do not assess its likelihood. BPA will not attempt to evaluate the relationship of the policy assumptions in the NRDC Scenario to the actual development of Pacific Northwest electric energy policies.

Table IV-32

LOAD GROWTH CHART
WEST GROUP AREA
1979 - 1998

Year	Projected Energy Loads - (Avg. MW) PNUCC Econometric Model 1/					Loads and Resources PNUCC West Group Forecast 2/		
	Mean Forecast (3.7% Ann. Growth)	95% Confidence Interval		80% Confidence Interval				
		High (4.8%)	Low (2.4%)	High (4.4%)	Low (2.9%)	Energy 3/ Resources (Avg. MW)	Peak Requirements (MW)	Peak Resources (MW)
1979-80	16,230	16,529	15,932	16,422	16,039	15,774	28,106	27,852
1980-81	16,956	17,425	16,487	17,256	16,656	16,021	29,452	28,093
1981-82	17,737	18,395	17,079	18,158	17,316	16,954	30,429	29,583
1982-83	18,603	19,471	17,736	19,159	18,048	17,178	31,806	29,292
1983-84	19,439	20,540	18,338	20,144	18,735	17,396	32,725	32,380
1984-85	20,182	21,541	18,823	21,052	19,312	18,314	33,859	32,375
1985-86	20,945	22,589	19,300	21,997	19,892	19,611	35,079	34,367
1986-87	21,722	23,680	19,764	22,975	20,468	21,204	35,774	36,206
1987-88	22,519	24,821	20,216	23,992	21,045	22,107	36,348	36,892
1988-89	23,254	25,840	20,668	24,909	21,599	22,857	37,568	37,763
1989-90	24,016	26,918	21,105	25,871	22,151	23,695	38,953	38,671
1990-91	24,795	28,059	21,531	26,884	22,706	23,827	40,425	38,270
1991-92	25,619	29,282	21,956	27,963	23,274	23,731	41,857	37,871
1992-93	26,460	30,560	22,359	29,084	23,835	23,631	43,411	37,437
1993-94	27,332	31,911	22,753	30,262	24,401	23,529	44,997	36,991
1994-95	28,229	33,330	23,128	31,493	24,964	23,398	46,624	36,524
1995-96	29,158	34,828	23,488	32,787	25,529	23,267	48,341	36,029
1996-97	30,121	36,409	23,833	34,145	26,097	23,164	50,024	35,539
1997-98	31,120	38,078	24,162	35,573	26,667	23,086	51,859	35,172

1/ PNUCC, "Econometric Model-Electricity Sales Forecast," March 1979. Sales projections generated by the model were increased 10 percent to account for transmission losses.

2/ PNUCC, "Long-Range Projection of Power Loads and Resources for Resource Planning," April 23, 1979.

3/ Figures in this column include those resources identified in Tables IV-1, IV-2, & IV-3 as well as those resources indicated in the PNUCC's, "Long-Range Projection of Power Loads & Resources for Resource Planning," April 23, 1979.

TABLE IV-33

NET ENERGY RESOURCE REQUIREMENTS BEYOND DEVELOPING PLANTS 1/
WEST GROUP AREA
1979 - 1998
ENERGY RESOURCES - (AVG. MW)

	Resource Scenarios 2/				
Year	A-100% Renewable	B-Maximum Conservation	C-100% Coal	D-100% Nuclear	E-Mixed Coal and Nuclear
1979-80	456	456	456	456	456
1980-81	935	935	935	935	935
1981-82	783	783	783	783	783
1982-83	1,425	1,425	1,425	1,425	1,425
1983-84	2,337	2,337	2,043	2,337	2,043
1984-85	2,445	2,445	1,868	2,445	1,868
1985-86	1,964	1,964	1,334	1,964	1,334
1986-87	1,915	1,915	1,285	1,148	518
1987-88	2,763	2,763	2,133	1,042	412
1988-89	3,642	3,642	3,012	1,027	397
1989-90	4,567	4,567	3,937	951	321
1990-91	5,420	5,420	4,790	1,598	968
1991-92	6,340	6,340	5,710	2,518	1,888
1992-93	7,281	7,281	6,651	3,459	2,829
1993-94	8,255	8,255	7,625	4,433	3,803
1994-95	9,283	9,283	8,653	5,461	4,831
1995-96	10,34	10,343	9,713	6,521	5,891
1996-97	11,40	11,40	10,779	7,587	6,957
1997-98	12,48	12,48	11,856	8,664	8,034

1/ Net energy resource requirements presented are the differences between projected loads in the mean forecast of the PNUCC econometric model and net resources as listed in the PNUCC "Long Range Projection of Loads and Resources for Resource Planning" April 1979.

2/ Resource scenarios are based on the following assumptions regarding current West Group Area resources:

A -- 100-Percent Renewable Resources - All West Group Area resources currently projected, except for Colstrip Units 3 and 4, Skagit Nuclear Plants 1 and 2, and Pebble Springs Nuclear Plants 1 and 2.

B -- Maximum Conservation - The same resources as under Scenario A.

C -- 100 Percent Coal-Fired Generation - West Group Area resources except for the Skagit and Pebble Springs nuclear plants.

D -- 100 Percent Nuclear Generation - West Group Area resources except for Colstrip Units 3 and 4.

E -- Mixed Coal-Fired and Nuclear Generation - All currently projected West Group Area resources.

TABLE IV-34

NET PEAK RESOURCE REQUIREMENTS BEYOND DEVELOPING PLANTS 1/
WEST GROUP AREA
1979-1998
PEAK RESOURCES - (MW)

	Resource Scenarios 2/				
Year	A-100% Renewable	B-Maximum Conservation	C-100% Coal	D-100% Nuclear	E-Mixed Coal and Nuclear
1979-80	254	254	254	254	254
1980-81	1,359	1,359	1,359	1,359	1,359
1981-82	846	846	846	846	846
1982-83	2,514	2,514	2,514	2,514	2,514
1983-84	765	765	345	765	345
1984-85	2,324	2,324	1,484	2,324	1,484
1985-86	1,552	1,552	712	1,552	712
1986-87	1,696	1,696	856	408	(-432) 3/
1987-88	2,844	2,844	2,004	296	(-544)
1988-89	4,481	4,481	3,641	645	(-195)
1989-90	6,218	6,218	5,378	1,122	282
1990-91	8,091	8,091	7,251	2,995	2,155
1991-92	9,922	9,922	9,082	4,826	3,986
1992-93	11,910	11,910	11,070	6,814	5,974
1993-94	13,942	13,942	13,102	8,846	8,006
1994-95	16,036	16,036	15,196	10,940	10,100
1995-96	18,248	18,248	17,408	13,152	12,312
1996-97	20,421	20,421	19,581	15,325	14,485
1997-98	22,623	22,623	21,783	17,527	16,687

1/ Peak requirements include reserves calculated according to PNUCC peak reserve criteria. Figures presented are the sum of loads and reserves minus net resources as listed in the PNUCC "Long Range Projection of Loads and Resources for Resource Planning" April 1979.

2/ Resource scenarios are based on the following assumptions regarding current West Group Area resources:

A -- 100% Renewable Resources - All West Group Area resources currently projected, except for Colstrip Units 3 and 4, Skagit Nuclear Plants 1 and 2, and Pebble Springs Nuclear Plants 1 and 2.
B -- Maximum Conservation - The same resources as under Scenario A.
C -- 100% Coal-Fired Generation - West Group Area resources except for the Skagit and Pebble Springs nuclear plants.
D -- 100% Nuclear Generation - West Group Area resources except for Colstrip Units 3 and 4.
E -- Mixed Coal-Fired and Nuclear Generation - All currently projected West Group Area resources.

3/ Figures in parentheses indicate peak resources in excess of projected requirements.

b. Assumptions.

A number of assumptions were made in preparing these resource scenarios. General assumptions common to all of the scenarios are explained below. In addition, particular assumptions used in generating individual scenarios are explained in the descriptions of the specific scenarios.

Several assumptions used here were taken from the PNUCC Blue Book (PNUCC, 1979). Firm hydro energy capability was assumed to be limited to energy available under critical water conditions. Energy reserves other than load growth reserves (as specified in the Blue Book), were assumed to be incorporated into energy resource planning via the plant capacity factors assumed and the interruptibility of portions of DSI loads. Thermal plant capacity factors were assumed to be 75 percent except for intermittent resources, where availability of input energy is not predictable. Peak reserves were projected based on the rolling criterion, which requires 12 percent reserve peak capacity for the first year of the planning period (in this case, 1979-80), increasing one percent per year to a maximum of 20 percent. Where pumped storage was included among peak resources, a ten percent average capacity factor was assumed, and therefore an energy penalty of 5 percent of projected capacity due to the net energy consumption involved in pumped storage operation.

The PNUCC projects deficits in generation under critical water conditions in all years of the planning interval 1979-1998. Although the scenarios were constructed to meet 1998 loads, it is assumed that a balance between loads and resources is achieved at the earliest possible time. However, due to the lead time which is necessary for the development of new resources, near-term deficits, particularly in the early 1980's, are unavoidable under critical water conditions in any of the scenarios. Strictly speaking, the impacts of those deficits could be considered to be part of the impacts of these resource scenarios. However, the intention here is to focus on the direct impacts of resource development, rather than to include the impacts of resource shortages, which are probabilistic (in relation to the likelihood of critical or near-critical water conditions) and which do not differ among the scenarios. (Differences between scenarios become apparent beginning in the mid-1980's, following the possible near-term deficits.) Thus, it is assumed here that near-term deficits are met through some combination of good water conditions, purchases from outside the region, short-term conservation and load management measures, curtailment of loads, and temporary relaxation of constraints on generator operation. None of these effects is assumed to continue past the time of the near-term deficits, so that each scenario provides resources (consistent with its assumed direction of resource development) to bridge the gap between resources in the process of development and net resources needed to meet projected 1998 loads, discounting any long-term benefits from stop-gap measures taken to avoid deficits.

The PNUCC econometric model indicates that 448 MW of conservation is already accounted for in the West Group Area forecast of 1998 loads and is thus included in all of the scenarios. This figure is an estimate of reductions in projected loads due to residential weatherization and residential solar space and water heating. This estimate does not imply that actual loads will be less than the PNUCC forecast; rather, it means that if loads develop as forecasted, 448 MW of conservation will have contributed toward meeting residential end-use energy demands.

Because of the peaking requirements under the five scenarios, each scenario includes some of the conventional hydro projects considered most likely to be developed prior to 1999 (PNUCC, 1979: Table 6). Although combustion turbines are a possible alternative to these forms of hydro peaking, they were not assumed here due to uncertainty of fuel supply and conflicts with national fuel use policy.

One important resource planning consideration has been omitted here, that is, the influence of resource costs on energy demand. The uncertainties of cost estimates for the various resource types and the iterative analysis necessary to assess cost effects on demand did not permit consideration of this effect in the construction of these scenarios. Instead, the simplifying assumption was adopted that the demand to be met would not differ among the scenarios regardless of the costs of resources developed to meet demands. This assumption is consistent with the data available and with the purpose of this document in assessing the environmental effects of alternate courses of regional resource development.

c. <u>Renewable and Conservation Resource Scenarios</u>.

These scenarios demonstrate strategies by which the region might meet projected 1998 loads through the development of renewable resources and conservation. Scenario A focuses on renewable forms of electrical generation. Scenario B relies instead on conservation and end-use energy resources which displace electrical loads.

Information regarding the potentials and impacts of renewable resources is in a state of rapid change. For this reason, the reader is cautioned that any conclusions which may be drawn from information presented here must be considered tentative and highly dependent on assumptions which have been made in the absence of readily available data.

Both scenarios include considerable diversity in resources. This reflects both the variety of renewable resources and the limitations on the potential of the individual resource types.

For some resources, these scenarios assume that the full potential of the resource (as presented in the previous section of this chapter) can be developed. This assumption is made without consideration of economic, technical, or institutional factors which may inhibit full development, but remains consistent with the concept that these scenarios are extreme cases of reliance on these technologies.

(1) Scenario A - 100 Percent Renewable Generation.

Resources included in this scenario are listed in Table IV-35. Assumptions used in applying potentials and estimating operational capabilities are explained in footnotes to the table. The net requirements for this scenario are 1998 requirements as shown in Tables IV-33 and IV-34.

Sites are not specified, nor are sizes of individual installations due to the uncertainty involved in predicting these parameters; if any of these resources were selected for actual development, subsequent studies would provide these particulars and refine the analysis of environmental impacts.

Important quantifiable impacts of the scenario are shown in Table IV-36. As noted previously, many of the values reported are uncertain and are subject to change as better information becomes available.

In addition to the quantifiable impacts presented in Table IV-36, there are a number of other impacts which are not quantifiable. Resources which tend to be sited in remote areas, including solar generating plants, wind generators, geothermal plants, and hydro generators (small hydro, system capacity additions, and pumped storage) will tend to have adverse impacts on wildlife and wildlife habitat through disruption of food supplies, ground cover, water supplies, and nesting and breeding areas. Noise and emissions will also be important influences on wildlife, particularly during construction, but in most cases also during the operation of the resource. Additional indirect impacts on land use, scenic and recreational values, and wildlife will also result from the need for transmission facilities to connect these generating resources to the regional transmission grid. Transmission impacts are discussed in greater detail in Section IV.A.3 above. Remote locations also are more likely to have scenic and recreational values which could be reduced or lost through development of energy resources.

The collection of forest residues as fuel for wood-fired generation would have potential for adverse impacts on forest ecosystems. Possible effects include soil compaction, erosion, changes in soil composition, increasing sediment loads in streams, water temperature changes, loss of nutrients, and eutrophication of water resources. Collection activities could have effects similar to those of construction of other resources, such as noise and emissions. Use of forest residues would also have some potential beneficial impacts, including improving the economic and esthetic value of the remaining forest, improving the vigor of aging or overcrowded stands, and reduced emissions compared to present disposal methods.

Table IV-35

1998 Energy and Peak Resources
Scenario A
100% Renewable Resources

Type of Resource	Energy (Ave MW)	Firm Peaking Capacity (MW)
Solar Central Station	3,510 1/	1,300 2/
Geothermal Generation 3/	2,424	3,232
Wood-Fired Generation 3/	2,039	2,720
Large Wind Generators	1,892 4/	500 2/
Small Hydro	1,370	1,500 5/
Municipal Waste Combustion 6/	390	600
Hydro Capacity Additions 7/	1,017	10,837
Pumped Storage 8/	- 145 9/	2,900
Net Resources	12,497	23,589
Net Requirements	12,486	22,623

Notes

1. Assumes 13,000 MW installed capacity operating at an average of 27 percent of capacity.

2. Assumes that 10 percent of potential installed capacity can be considered firm due to resource diversity across the region.

3. Assumes a 75 percent capacity factor.

4. Assumes 5,000 MW installed capacity operating at an average of approximately 37.8 percent of capacity.

5. Assumes that 1,500 MW of total potential installed capacity (3,200 MW) is firm peaking capacity, due to seasonal peaking limitations.

6. Assumes a 65 percent capacity factor.

7. All of these scenarios include hydro projects considered by the PNUCC to be among those most likely to be developed by 1999, as shown in Table 6 of the "Blue Book" (PNUCC, 1979).

8. Projects included here are: Antilon Lake (1,400 MW) and Browns Canyon (1,500 MW).

9. The negative value reflects the net energy consumption involved in pumped storage operation, given the 10 percent capacity factor assumed by the PNUCC.

TABLE IV-36

IMPACTS SUMMARY
Scenario A
100% Renewable Generation

Resource Potential	Solar Central Station 1/	Geothermal Generation	Wood-Fired Generation 2/	Large Wind Generation	Resource: Small Hydro Generation	Resource: Municipal Waste Combustion	Hydro Additions	Pumped Storage	Total
Firm Peaking Capacity (MW)	1,300	3,232	2,720	500	1,500	600	10,837	2,900	23,039
Energy (ave. MW)	3,510	2,424	2,039	1,892	1,370	390	1,017	-145	12,541
Impacts									
Land Use (acres)	250,000	12,100	2,870 +33/yr 3/	127,000	1,370 4/	200 +15/yr	65,600 5/	772	459,000 +48/yr 3/
Water Consumption (acre-feet/yr)	7,920	119,000	62,800	None	None 7/	140,000	None 6/	None 6/	330,000
Water Emissions (tons/yr)									
Suspended/ Dissolved Solids	None	None	36.8	None	None	None	None	None	None
Inorganics	None	None	423 7/	None	None	None	None	None	36.8
Organics	None	None	4.9	None	None	None	None	None	4.9
Other	None	None	None	None	None	771 8/	None	None	771
Air Emissions (tons/yr)									
Sulfurous	None	95,700	15,200	None	None	2,240	None	None	113,000
Nitrous	None	132,000	79,100	None	None	874	None	None	212,000
Particulates	None	None	13,100	None	None	1,860	None	None	15,000
Hydrocarbons	None	97,700	2,870	None	None	NA	None	None	101,000
CO	None	None	24,600	None	None	NA	None	None	24,600
Other	None	1.62×10^6 9/	15.1 10/	None	None	None	None	None	1.62×10^6
Solid Waste (tons/yr)	None	None	1.15×10^6	None	None	526,000 11/	None	None	1.67×10^6
Heat Releases ($\times 10^9$ Btu/yr)	584,000	371,000	193,000	None	None	46,600	None	None	1.19×10^6

Notes

1/ Assumes solar thermal generation rather than photovoltaic conversion.

2/ Impacts are based on 50 MW plant size.

3/ Assumes wastes require 1 acre for disposal of each 35,000 tons generated.

4/ Assumes an average of 1 acre land requirement for each average megawatt produced for new projects. No additional land would be required for installation of generators at existing sites.

5/ Assumes 500 acres each for Klamath River, Copper Creek, and Quartz Creek additions to the hydro systems.

6/ Does not includes loss due to evaporation from reservoir surfaces.

7/ Various oxides.

8/ HCl - 581.1 tons/yr; other emissions - 190 tons/yr.

9/ CO_2, N_2, H_2, Ar.

10/ Trace metals.

11/ Char.

The hydro developments involved in this scenario merit additional discussion. As explained in detail in Section IV.A.1.a.(1)(b), above, hydro resources have adverse impacts on fisheries through loss of spawning areas, interference with migrations, nitrogen supersaturation, and temperature effects of reservoir impoundment. These effects would be increased through the developments included in this scenario. Recreation impacts through reservoir operations would also be increased, particularly at pumped storage projects operated for daily and weekly peak generation. Extreme fluctuations at these projects could be a hazard to recreationists. Mitigation measures developed to reduce these impacts from the existing hydro system could also be applied to small hydro, pumped storage, and capacity addition projects. Scenic areas otherwise relatively undisturbed would be permanently altered by the construction of dams and the consequent impoundment of water.

Large wind generators have their own characteristic impacts regarding land use, esthetics, and television and microwave interference. The magnitude of these and other impacts will be site specific. Infrasound was encountered with the Department of Energy's MOD-1 wind turbine located at Boone, North Carolina. The causes and mitigating measures of this particular problem are currently being investigated by the Solar Energy Research Institute. This problem is not expected to be generic in nature.

Resources resulting in large quantities of air emissions could interfere with scenic values by reducing visibility, as well as creating a hazard to human health, particularly if the generators are likely to be located near load centers (for instance, municipal waste combustion or wood-fired generation). If development of new sources of pollution requires reduction of emissions from other sources in a given area, these resources could impose costs on other sources of pollution, or constrain industrial operations or development in the area.

(2) Scenario B - Maximum Conservation.

Resources included in this scenario are shown in Table IV-37. The various assumptions required to estimate resource potentials are explained in the footnotes to the table. The assumption of primarily end-use resources in this scenario resulted in a greater need for clarifying assumptions than in the other scenarios, due to the diverse nature of end-use resources compared to central station generating resources. The net requirements indicated are 1998 requirements for this scenario as shown in Tables IV-33 and IV-34.

Important quantifiable impacts of this scenario are shown in Table IV-38. Limitations in impact data are explained in footnotes to the table. The diversity of specific applications of end-use energy resources severely complicates the process of assessing impacts on a regional scale, thus the estimates presented here are likely to be improved upon considerably as data on these resources accumulates.

TABLE IV-37

1998 ENERGY AND PEAK RESOURCES
Scenario B
Maximum Conservation

Type of Resource	Energy (Ave. MW or equivalent)	Firm Peaking Capacity (MW or equivalent)
Conservation	8,534	10,517 1/
End-Use of Wood	1,699 2/	2,178 3/
Small Solar Applications	1,100	110 4/
Cogeneration	503 5/	1,006
Municipal Waste Combustion	390 6/	600
End-Use of Geothermal Energy	123	157 7/
Load Management	0	1,500 8/
Hydro Capacity Additions 9/	771	7,165
Total Additional Resources	13,120	23,233
Adjustment for Existing Conservation 10/	-448	-574 11/
Net Resources	12,672	22,659
Net Requirements	12,486	22,623

Notes

1/ The peaking value of conservation was calculated based on the January system load factor (78 percent) applied to the conservation potential in the residential and commercial sectors. The energy value of conservation in those sectors (7,029 average MW) was assumed to be 78 percent of the peak value, yielding a peak value of 9,011 MW. Industrial conservation was not assumed to vary during daily or annual load cycles. This assumption is equivalent to assuming that a minimum of 33.0 percent of energy conservation is equally distributed during the daily peak intervals in peak seasons (26.8 percent of the year).

2/ The electrical generation potential of wood was estimated at 2,039 ave. MW from 254 x 10^{12} Btu of collectable forest and mill residues, for a conversion efficiency of 24.0 percent. End-use conversion efficiency was assumed to be 40 percent, based on wood stove efficiencies which range up to 60 percent. The total end-use potential (3,398 Ave. MW) was then reduced by half to compensate for displacement of other fuels, as well as electricity, by wood end-use.

3/ The peaking value of wood end-use was calculated by the same method as the peaking value of conservation, under the assumption that the end-use of wood displaces peak electrical loads proportionately to residential and commercial conservation, as in Note 1 above.

4/ Assumes that small solar applications displace 110 MW of firm capacity due to solar diversity in the region.

5/ Assumes that cogeneration facilities will operate at a 50 percent capacity factor.

6/ Assumes a 65 percent capacity factor for municipal waste combustion facilities.

7/ The peaking value of geothermal end-use was calculated as for wood end-use and conservation, as in Notes 1 and 3 above.

8/ Based on an estimate of 596 MW potential reduction in 1979 peak loads through load management of residential water heating loads (see p. IV-127), a proportional reduction in 1998 peak loads would be 890 MW. Assuming a similar reduction in residential space heating loads is also possible, 1,378 MW of additional peak reduction would be available in 1998, for a total potential of 2,268 MW from these two sources.

9/ From Table 6 of the Blue Book (PNUCC, 1979).

10/ The PNUCC econometric model, which was used here to estimate resource requirements, includes some projected conservation measures and solar water heating and space heating applications which are also included in the potential estimated for the conservation resource. This adjustment compensates for conservation which is counted both as a resource and as an influence on projected loads.

11/ Peaking value calculated as for residential and commercial conservation in Note 1 above.

TABLE IV-38

IMPACTS SUMMARY
Scenario B
Maximum Conservation

Resource Potential	Conservation 1/	Small Solar Applications	End-Use of Wood 2/	Cogeneration 3/	Municipal Waste Combustion	End-Use Geothermal Energy 4/	Load Management 5/	Hydro Capacity Additions	Total
Firm Peaking Capacity (MW)	10,517 6/	110	2,178	1,006	600	157	1,500	7,165	23,233 6/
Energy (ave MW)	8,534 6/	1,100	1,699	503	390	123	0	771	13,120 6/
Impacts									
Land Use (acres)	None	56,300 7/	None +2/yr 8/	3,500 +65/yr 8/	200 acres +15/yr 8/	749 9/	None	43,800 10/	104,000 +82/yr 8/
Water Consumption (acre-feet/yr)	None	335,000 11/	None	18,400	140,000	48	None	None 12/	493,000
Water Emissions (tons/yr)									
Suspended/Dissolved Solids	None	None	None	360	None	None	None	None	360
Inorganics	None	None	None	None	None	None	None	None	None
Organics	None	None	None	None	None	None	None	None	None
Other	None	ethylene 13/ glycol 2.14×10^8 gallons	None	None	771 14/	None	None	None	771 $+2.14 \times 10^8$ gallons
Air Emissions (tons/yr)									
Sulfurous	None	None	None	5,700	15,170	33.1	None	None	20,900
Nitrous	None	None	895	25,400	874	46	None	None	27,200
Particulates	None	None	17,900	9,800	13,120	None	None	None	40,800
Hydrocarbons	None	None	4,480	1,100	2,870	33.1	None	None	8,480
CO	None	None	107,000	2,600	24,600	None	None	None	135,000
Other	None	None	None	None	None	541 15/	None	None	541
Solid Wastes (tons/yr)	None	None	71,600 16/	735,000 17/	526,000 18/	None	None	None	1.33×10^6
Heat Releases ($\times 10^9$ Btu/yr)	None	None	127,000	22,000	46,600 19/	NA	None	None	196,000

Notes

1/ Does not include impacts occurring in the production of conservation products.

2/ Emissions values are based on end-use of wood in fireplaces rather than wood stoves or other applications, which may result in either greater or lesser values. Does not include land-use, water consumption, or emissions impacts of medium-scale industrial or commercial applications.

3/ Assumes all cogeneration is coal-fired. Cogeneration in the Pacific Northwest is more likely to be wood-fired, but coal was assumed here for purposes of indicating worst-case impacts.

4/ Assumes reinjection of water into the aquifer after its heat is used.

5/ Does not includes impacts occurring in the production of load management products.

6/ Does not include adjustment for conservation measures already included in the PNUCC econometric model, which reduces projected peak capacity by 574 MW and energy by 448 average MW.

7/ Assumes 400 MW of displacement of electrical loads is due to application of solar energy to production of hot water for industries. (Source: U.S. Department of Energy, Environmental Data For Energy Technology Analysis, Vol. 1, p. VI-5).

8/ Assumes wastes require 1 acre for disposal of each 35,000 tons generated.

9/ Assumes 200 miles of piping with a 30-foot right-of-way.

10/ Assumes 500 acres for Klamath River hydro developments.

11/ Assumes 400 MW of displacement of electrical loads is due to application of solar energy to heating and cooling of buildings (Source: See Note F above, p. VI-7).

12/ Does not include loss due to evaporation from reservoir surfaces.

13/ Assumes that water is the storage medium for solar heating and cooling systems with ethylene glycol added to prevent freezing, and that storage is flushed once every 4 years (Source: See Note 7 above, p. VI-7).

14/ HC1-581.1 tons/yr; other emissions 190 tons/yr.

15/ CO_2, N_2, H_2, Ar.

16/ Ash.

17/ Ash - 315,000 tons/yr; limestone sludge - 420,000 tons/yr.

18/ Char.

19/ Based on 20 percent conversion efficiency in generating electricity.

Impacts of this scenario which could not be quantified include impacts of hydro development comparable to those described under Scenario A (except somewhat less in quantity due to the lesser amount of pumped storage under this scenario compared to Scenario A), the visual and human health impacts of emissions resulting from end-use of wood and generation fired by municipal wastes, as well as those of cogeneration, and the impacts of the manufacture of materials for load management, energy conservation, end-use of wood, and end-use of geothermal energy.

Generation by combustion of municipal wastes, together with cogeneration and end-use of wood, will tend to affect air quality at load centers. Generation sited away from load centers is not as constrained in allowable emissions as load center generation, thus this scenario would tend either to result in higher costs for emission controls or reduced air quality in populated areas. Wood stoves are not subject to air emissions standards, thus they would contribute essentially uncontrolled emissions to local airsheds. Collectively, these emissions would adversely affect visibility and human health in the vicinity of these resources.

Wood burning also has an impact on human health due to the increased risk of house fires. Widespread use of wood stoves in recent years has resulted in a dramatic increase in fires due to improper installation or misuse of wood heaters. An impact of wood use on the scale assumed in this scenario would be an increase in the risk of property damage, injury, or loss of life due to house fires.

Manufacture of conservation, load management, and other end-use resource materials could result in increased emissions to air and water, increased use of mineral resources, and increased consumption of energy inputs to these manufacturing processes. It is likely that much of these increased impacts would occur outside the region.

The construction of distribution systems for geothermal end-use heat could have a significant effect on wildlife and ecosystems in remote areas where geothermal resources are available. Construction activities would result in traffic, noise, emissions, disruption of habitat, and removal of vegetation. Once the system was completed, however, these impacts would probably be minimal.

The use of end use resources in this scenario would reduce the impacts of transmission development on land-use, wildlife, scenic values, and other environmental resources, due to the reduced need for such facilities. Resource needs would also be somewhat reduced, due to lesser transmission losses incurred in supplying energy (although this adjustment in resource needs is not shown in Table IV-37).

d. Conventional Thermal Resource Scenarios.

The following scenarios present strategies to meet projected 1998 loads through the development of conventional thermal generation, i.e., baseload coal-fired and nuclear powerplants. Scenario C is designed to meet loads through development of coal-fired baseload generation only, including Colstrip units 3 and 4. Scenario D assumes instead that only nuclear baseload generation is developed, including Pebble Springs nuclear plants 1 and 2 and Columbia nuclear plants 1 and 2. Scenario E assumes a mixture of coal-fired and nuclear generation, including all of the Colstrip, Pebble Springs, and Columbia plants, and meeting additional requirements equally with both coal-fired and nuclear generation. All three scenarios require considerable quantities of peaking capacity, which, like the renewable resource and conservation scenarios, are assumed to be provided by capacity additions to the hydro system and pumped storage development.

The scale of powerplants under these scenarios is assumed to be 500 MW for coal-fired plants and 1,250 MW for nuclear plants. For coal plants, a worst-case assumption of load center generation was adopted in view of the uncertainty regarding coal plant siting.

Nuclear generation in these scenarios is based on the assumptions that sufficient fuel will be available to supply the plants through their useful lives, and that waste disposal or other unresolved aspects of nuclear technology will not prevent their operation at projected output.

(1) Scenario C - 100 Percent Coal-Fired Generation.

Resources included in this scenario are listed in Table IV-39. Net requirements shown are 1998 requirements taken from Tables IV-33 and IV-34.

Important quantifiable impacts of this scenario are shown in Table IV-40.

In addition to the impacts shown in the table, there are some important unquantifiable impacts resulting from this scenario. As noted in the discussion of Scenario A, the hydro capacity additions which provide peaking capacity under this scenario result in impacts on fisheries, scenic values, and recreation.

The assumption that coal-fired generation (other than Colstrip units 3 and 4) would be sited near load centers would have two major effects. First, location near load centers would reduce the need for transmission facilities, thus also reducing line losses, land use, wildlife impacts, and other environmental effects of transmission development. These reductions in impacts would be balanced by an increase in impacts due to transportation of coal to plants near load centers. Second, the emissions produced by load center generation could

TABLE IV-39

1998 ENERGY AND PEAK RESOURCES
Scenario C
100% Coal-Fired Generation

Type of Resource	Energy (Ave. MW)	Firm Peaking Capacity (MW)
Coal-fired Generation 1/	12,000	16,000
Hydro Capacity Additions 2/	0	6,234
Net Additional Resources	12,000	22,234
Net Requirements	11,856	21,783
Colstrip Units 3 and 4	630	840
Total Additional Resources	12,630	23,074

Notes

1/ Assumes a 500 MW plant size and a 75 percent plant capacity factor.

2/ From Table 6 of the Blue Book (PNUCC, 1979).

TABLE IV-40

IMPACTS SUMMARY
Scenario C
100% Coal-Fired Generation

Resource Potential	Coal Plants 1/	Colstrip Units 3 & 4 1/	Resource Hydro Capacity Additions	Total
Resource Output				
Firm Peaking Capacity (MW)	16,000	840	6,234	23,074
Energy (ave. MW)	12,000	630	0	12,630
Impacts				
Land Use (acres)	56,000 1040/yr	924 55/yr	0 2/	57,000 1100/yr
Water Consumption (acre-feet/yr)	294,000	15,500	None 3/	310,000
Water Emissions (tons/yr)				
Suspended/ Dissolved Solids	5,760	302	None	6,060
Inorganics	None	None	None	None
Organics	None	None	None	None
Other	None	None	None	None
Air Emissions (tons/yr) 4/				
Sulfurous	91,200	4,200	None	95,400
Nitrous	342,000	17,400	None	359,000
Particulates	138,000	2,180	None	140,000
Hydrocarbons	17,600	440	None	18,000
CO	41,600	1,510	None	43,100
Other	None	None	None	None
Solid Waste (tons/yr)	8.42×10^6	442,000	None	8.86×10^6
Heat Releases ($\times 10^9$ Btu/yr)	642,000	32,800	None	657,000

Notes

1. Impacts are based on impacts of 1,000 MWe Pacific Northwest coal plants sited at load centers as shown in Table V-54 in Part 1 of the original Draft Role EIS (p. V-241), as updated in August 1979 (see p. IV-230 above).

2. All capacity additions assumed here are generator additions at existing dams and do not result in additional land use.

3. Does not include loss due to evaporation from reservoir surfaces.

4. For a discussion of the relationship of residuals to health effects, refer to "Coal-Fired Generation" under IV.B.2.d.

stress air quality, water supplies, and other environmental resources in populated areas, increasing the costs of pollution control, limiting development of industries with similar emissions (due to regulations to prevent deterioration in air quality), and increasing human health impacts of substances emitted. Visual resources would also be adversely affected by increased air emissions resulting from coal-fired generation.

(2) Scenario D - 100 Percent Nuclear Generation.

Resources included in this scenario are shown in Table IV-41. Net requirements shown are 1998 requirements as provided in Tables IV-33 and IV-34.

Important quantifiable impacts are shown in Table IV-42.

In addition, impacts which cannot be quantified include the impacts of hydro development (as in the other scenarios), the impacts of the development of transmission lines, and the impacts relating to the radiological hazards of nuclear technology.

Impacts of hydro development, including capacity additions to the hydro system and pumped storage, are discussed in Section IV.A.1.a.(1)(b) above. Impacts of hydro development in these scenarios are briefly discussed under Scenario A above. Hydro development impacts are similar among all of the scenarios in that all five scenarios include some hydro system capacity additions.

Assuming that nuclear plants are not likely to be sited near major population centers, they require transmission capacity to integrate their output into the regional transmission grid. Impacts of transmission include land use, disruption of wildlife, and possible interference with scenic values. Because sites are unknown for the prospective nuclear plants discussed here, precise estimates of transmission requirements are not now available.

Radiological hazards of nuclear generating technology have been the focus of a continuing debate. For the purposes of this discussion, it is acknowledged that nuclear power development increases the risk of harm to human populations due to accidental release of radioactive substances and handling and processing of nuclear wastes. This document will not attempt to assess the magnitude of this risk. Under normal operating conditions, the risk to human health of nuclear power generation is assumed to be quite small.

TABLE IV-41

1998 ENERGY AND PEAK RESOURCES
Scenario D
100% Nuclear Generation

Type of Resource	Energy (Ave. MW)	Firm Peaking Capacity (MW)
Nuclear Generation 1/	9,375	12,500
Hydro Capacity Additions 2/	0	5,624
Net Additional Resources	9,375	18,124
Net Requirements	8,664	17,527
Pebble Springs Nuclear Plants 1 and 2	1,890	2,520
Columbia Nuclear Plants 1 and 2	1,932	2,576
Total Additional Resources	13,197	23,220

1/ Assumes a 1,250-MW plant size and a 75 percent plant capacity factor.

2/ From Table 6 of the Blue Book (PNUCC, 1979).

TABLE IV-42

IMPACTS SUMMARY
Scenario D
100% Nuclear Generation

Resource Potential	Nuclear Plants 1/	Pebble Springs & Columbia Plants 1/	Hydro Capacity Additions	Total
Resource Output				
Firm Peaking Capacity (MW)	12,500	5,096	5,624	23,220
Energy (ave. MW)	9,375	3,822	0	13,197
Impacts				
Land Use (acres)	8,920 +694/yr	3,640 +283/yr	0 2/	12,560 +977/yr
Water Consumption (acre-feet/yr)	882,000	335,000	None 3/	1.16×10^6
Water Emissions (tons/yr)				
Suspended/ Dissolved Solids	333,000	136,000	None	469,000
Inorganics	1,240	510	None	1,750
Organics	738	302	None	1,040
Other	None	None	None	None
Air Emissions (tons/yr)				
Sulfurous	61,200	25,000	None	86,200
Nitrous	16,200	6,620	None	22,800
Particulates	15,000	6,120	None	21,100
Hydrocarbons	188	76.4	None	264
CO	None	None	None	None
Other	None	None	None	None
Solid Waste (tons/yr)	3.88×10^7	1.58×10^7	None	5.46×10^7
Heat Releases ($\times 10^9$ Btu/yr)	678,000	276,000	None	954,000

Notes

1/ Impacts are based on impacts of 1,000 MWe nuclear plants as shown in Table V-55 in Part 1 of the original Draft Role EIS (p. V-246).

2/ All capacity additions assumed here are generator additions at existing dams and do not result in additional land use.

3/ Does not include loss due to evaporation from reservoir surfaces.

(3) Scenario E - Mixed Coal-Fired and Nuclear Generation.

Table IV-43 indicates resources projected for this scenario to meet net 1998 resource requirements as shown in Tables IV-33 and IV-34. Important quantifiable impacts are shown in Table IV-44. To avoid repetition, the reader is referred to discussion of Scenarios C and D above for information on unquantifiable impacts.

TABLE IV-43

1998 ENERGY AND PEAK RESOURCES
Scenario E
Mixed Coal-Fired and Nuclear Generation

Type of Resource	Energy (Ave. MW)	Firm Peaking Capacity (MW)
Coal-Fired Generation 1/	4,500	6,000
Nuclear Generation 2/	3,750	5,000
Hydro Capacity Additions 3/	0	6,234
Net Additional Resources	8,250	17,234
Net Requirements	8,034	16,687
Colstrip Units 3 and 4	630	840
Pebble Springs Nuclear Plants 1 and 2	1,890	2,520
Columbia Nuclear Plants 1 and 2	1,932	2,576
Total Additional Resources	12,702	23,170

1/ Assumes a 500-MW plant size and a 75 percent plant capacity factor.
2/ Assumes a 1,250-MW plant size and a 75 percent plant capacity factor.
3/ From Table 6 of the Blue Book (PNUCC, 1979).

TABLE IV-44

IMPACTS SUMMARY
Scenario E
Mixed Coal-Fired and Nuclear Generation

Resource Potential	Coal Plants 1/	Nuclear Plants 2/	Pebble Springs & Columbia Plants 2/	Resource: Colstrip Units 3 & 4 1/	Hydro Capacity Additions	Total
Firm Peaking Capacity (MW)	6,000	5,000	5,096	840	6,234	23,170
Energy (ave. MW)	4,500	3,750	3,822	630	0	12,702
Impacts						
Land Use (acres)	21,000	3,570	3,640	924	0 3/	29,100
Water Consumption (acre-feet/yr)	110,000	329,000	335,000	15,500	None 4/	790,000
Water Emissions (tons/yr)						
Suspended/ Dissolved Solids	2,160	133,500	136,000	302	None	272,000
Inorganics	None	500	510	None	None	1,000
Organics	None	295	302	None	None	597
Other	None	None	None	None	None	None
Air Emissions (tons/yr) 5/						
Sulfurous	34,200	24,500	25,000	4,200	None	87,900
Nitrous	128,000	6,500	6,620	17,400	None	159,000
Particulates	51,600	6,000	6,120	2,180	None	65,900
Hydrocarbons	6,600	75	76.4	440	None	7,190
CO	15,600	None	None	1,510	None	17,100
Other	None	None	None	None	None	None
Solid Waste (tons/yr)	3.16×10^{6}	1.55×10^{7}	1.58×10^{7}	442,000	None	3.49×10^{7}
Heat Releases ($\times10^{9}$ Btu/yr)	234,000	271,000	276,000	32,800	None	814,000

Notes

1/ Impacts are based on impacts of 1,000 MWe Pacific Northwest coal plants sited at load centers as shown in Table V-54 in Part 1 of the original Draft Role EIS (p. V-241), as updated in August 1979 (see p. IV-230 above).

2/ Impacts are based on impacts of 1,000 MWe Pacific Northwest nuclear plants as shown in Table V-55 in Part 1 of the original Draft Role EIS (p. 246).

3/ All capacity additions assumed here are generator additions at existing dams and do not result in additional land use.

4/ Does not include loss due to evaporation from reservoir surfaces.

5/ For a discussion of the relationship of residuals to health effects, refer to "Coal-Fired Generation" under IV.B.2.d.

(4) Scenario F - NRDC's Alternative Scenario.

The following summary prepared by BPA is intended to provide a representation of a document prepared by the Natural Resources Defense Council (NRDC) entitled, "Choosing an Electrical Energy Future for the Pacific Northwest: An Alternative Scenario."

As mentioned previously, although the Alternative Scenario is similar to Scenario B in terms of its reliance upon conservation and renewable resource development, it is distinguished from Scenario B in that it is portrayed by NRDC as an exercise in the possible. To fully appreciate NRDC's position as reflected in their Alternative Scenario, the reviewer is encouraged to read the full text which is available from NRDC. (A detailed evaluation of the Alternative Scenario is provided in Attachment C to this document.)

Although a summary of the Alternative Scenario is presented below to facilitate a comparison to the "worst-case" scenarios, it is not possible to include a quantitative comparison. The reason for this is that NRDC used a different load projection from that given in Table IV-32 and because the baseline projection they used is not explicit within the Alternative Scenario. As a result, it is not possible to prepare a detailed listing of resources for the Alternative Scenario similar to that given in Table IV-37. Nevertheless, because the Alternative Scenario is similar to Scenario B from a resource perspective, the impacts of these scenarios are also assumed to be similar (see Table IV-38).

Methodology. The methodology attempted in the Scenario was end-use analysis, a technique which works by summing up the energy consumption of the myriad applications of electric energy in the Pacific Northwest. End-use analysis permits a detailed assessment of the effects of many conservation options which are open to decision-makers, such as weatherization programs, applicance efficiency standards, and solar water heater incentives. 1975 was used as the base year for the Scenario, and projections were made for the years 1985 and 1995. The geographic region to which the Scenario was addressed was the West Group Area of the Northwest Power Pool.

The analysis of the residential sector in the Scenario was split into two parts: space heating, and all other uses. The analysis of space heating requirements was based largely on a 1976 report to BPA by Skidmore, Owings, and Merrill (SOM). The projection of the housing stock in 1985 and 1995 was taken from BPA household projections for the states of Washington, Oregon, Idaho, and western Montana. Assumptions were made about the housing mix between single-family and multifamily dwellings. Most dwellings existing in 1975 were assumed to be retrofitted by 1995 with insulation and other conservation measures so that they would consume only 45 to 55 percent of the electric energy for space heating than they otherwise would. Some pre-1976 dwellings were assumed to switch from fossil fuel to electricity for space heating, and 25 percent of existing single-family dwellings were assumed to have heat pumps replace their current heating systems by 1995.

All new dwellings built beyond 1975 were assumed to be built to stringent conservation standards, with 95 percent using electricity for space heating. A growing proportion of new homes are assumed to have heat pumps and (for single-family dwellings only) passive solar systems.

For all other residential uses (water heating, lighting, and appliances), NRDC made assumptions concerning the number of residences, using those appliances, and multiplied that by the average annual kWh usage of each appliance. Appliance efficiency is assumed to improve as a result of Federally-mandated appliance efficiency standards. Water heating is also reduced by the assumption that by 1995, 20 percent of all single-family homes will have heat pump water heaters and 8 percent will have solar water heaters.

The results for the residential sector as a whole reveal that the NRDC Scenario loads in 1995 are 30 percent lower than the PNUCC/BPA residential estimate, amounting to a little over 2,700 average megawatts difference.

In the commercial sector, NRDC first projected an independent baseline of total energy consumption before subtracting the savings expected from conservation. The baseline projection was made by assuming commercial floor space and energy demands would be directly proportional to the growth in nonbasic and Federal employment (which was taken from BPA's Pacific Northwest employment projections). Total commercial floor space was broken down into five building types, and after applying a list of conservation measures developed in the SOM study, the energy consumption required by the five building types was reduced by 43 to 83 percent by 1995 depending on building type. Energy requirements were also reduced 1 percent in 1985 and 5 percent in 1995 due to the combined contribution of solar water heating, geothermal direct use applications, and total energy systems. The resulting total energy requirements were then converted to electric energy requirements by assuming certain electrical saturation values and fuel switchovers from fossil fuel to electricity.

The results for the commercial sector indicate that electricity demands would actually decrease in the Scenario by 8 percent between 1975 and 1995. Compared with PNUCC/BPA estimate, the

NRDC Scenario is 67 percent lower in 1995, amounting to a difference of almost 3,700 average megawatts.

The manufacturing sector in the Scenario, like the commercial sector, has an independent, underlying projection of energy consumption before conservation savings are subtracted. This underlying projection assumes that energy per employee will remain constant, and thus total energy requirements will grow directly in proportion with manufacturing employment (again take from BPA projections). Savings factors, taken from a report on California energy use, were applied to 15 manufacturing subsectors, although special calculations were made for the aluminum industry. These savings factors ranged from 18 to 29 percent for the 15 subsectors in 1995, while the aluminum industry is expected to save 40 percent by that year.

The energy requirements per job were adjusted upward to reflect the substitution of energy for labor, and the electrical requirements for manufacturing also take into account some degree of fuel switching from fossil fuels to electricity. Finally, the contribution from industrial cogeneration was taken into account (750 megawatts of capacity in 1985 and 1,645 megawatts in 1995).

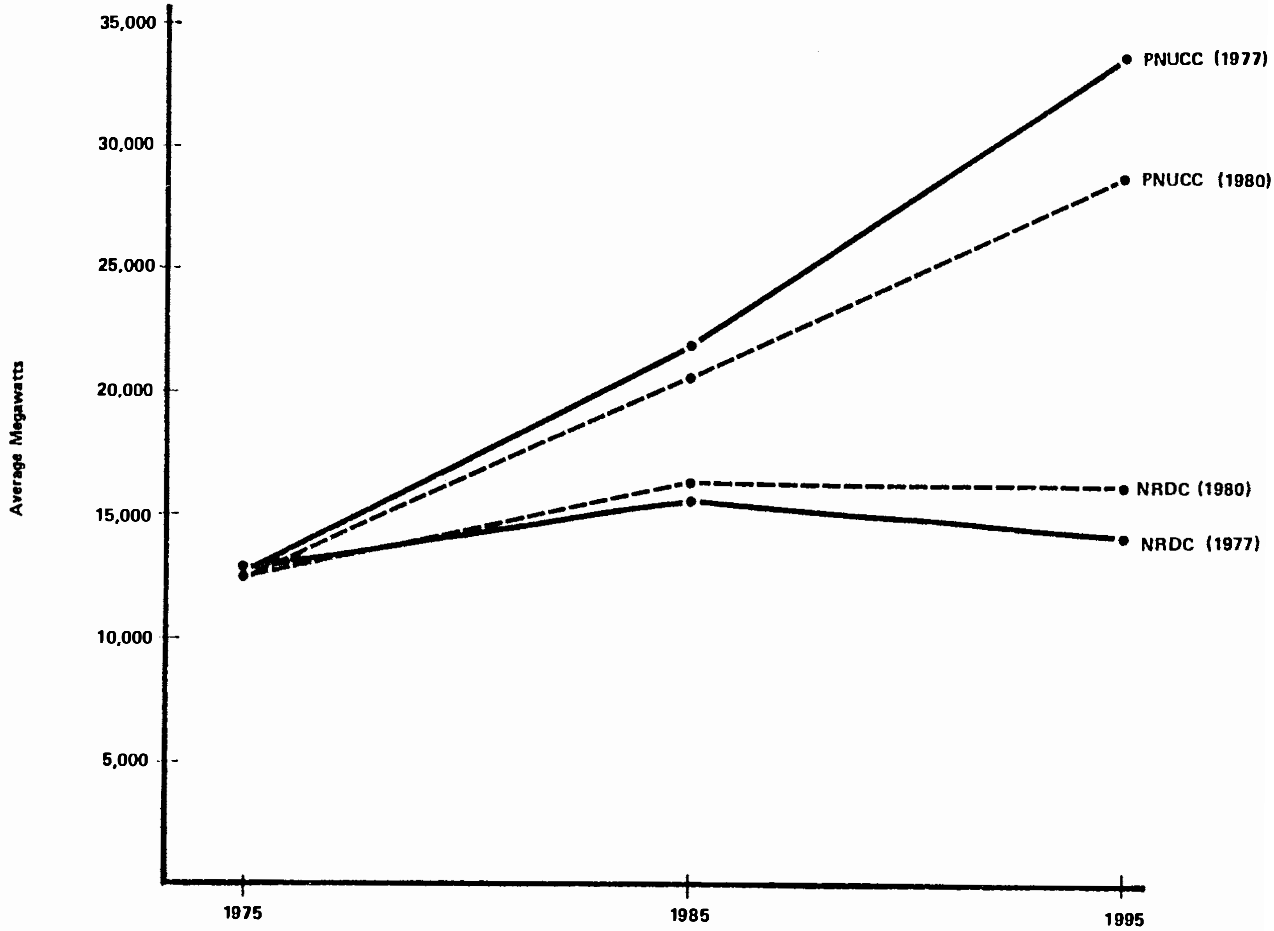
The results for the manufacturing sector show the NRDC Scenario at a level of 42 percent below the PNUCC/BPA estimate by 1995, a difference of over 4,500 average megawatts.

The agricultural sector consumes only a small portion of total regional energy requirements. The Scenario uses BPA projections of irrigated acreage and kWh/acre to project a baseline, and then assumes efficiency improvements and a limited contribution from on-site wind machines and photovoltaic cells. As a result, the Scenario projects a 1995 consumption level for agriculture that is 48 percent lower than the PNUCC/BPA estimate, amounting to somewhat over 500 average megawatts difference.

Total Results - The total results for the Scenario are depicted on Figure IV-7. West Group Area loads increase about 30 percent between 1975 and 1985, and then level off between 1985 and 1995. For comparison purposes, Figure IV-7 also includes the official 1980 PNUCC West Group Forecast and the results from the 1977 version of the NRDC Scenario. As can be seen, the more recent 1980 Scenario results in a consumption level in 1995 of about 1,500 average megawatts higher than the 1977 Scenario. This result is primarily due to two factors: (1) BPA's population and employment projections were increased, and (2) unlike the 1977 Scenario, all of the aluminum industry is assumed to remain in the Pacific Northwest. The full effect of these two factors was somewhat offset by assuming a higher rate of adoption of heat pumps, solar space and water heating, geothermal, and (most significantly) cogeneration.

FIGURE IV-7

COMPARISON OF 1977 AND 1980 NRDC 'ALTERNATIVE SCENARIO' RESULTS



At the same time that NRDC increased the 1995 demands, the official PNUCC West Group forecast for that year was significantly reduced, by slightly over 5,000 average megawatts. Thus, the gap between the utility forecast and the Scenario has been reduced a great deal since 1977. There is still a difference between them of 12,700 average megawatts, though, with the utilities' forecast 75 percent higher than the Scenario only 15 years into the future.

In terms of the Scenario's conclusion regarding the need for new central-station generation, there has been little change from the 1977 version. The Scenario sees no need for new powerplants through 1995 beyond four units that are currently being built (Boardman and the first three WPPSS plants). Several other plants which are included in the PNUCC West Group Forecast of Loads and Resources (including some alredy licensed and under construction, e.g., Colstrip 3 and 4, WPPSS 4 and 5) no longer would be needed according to the Scenario, at least through 1995. The Scenario has included a large amount of new wind generation in its calculations, totaling almost 1,000 megawatts by 1995. With these changes, small resource surpluses are seen in the Scenario.

Implementation - NRDC devotes a large amount of attention to the problems of getting the Scenario's assumptions implemented within the required time frame. A great number of implementation actions at all levels (governments, utilities, and others) have been initiated during the past 5 years, and an extensive description of these actions is provided in the Scenario. Much of that description, though, is devoted to the failings and shortcomings of those programs. Many new programs are proposed by NRDC to fill in the gaps in required incentives, and several institutional changes are advocated by NRDC to accomplish this.

BPA's role in promoting conservation, both directly and indirectly, is much expanded under the Scenario. Rate reform, energy allocations policy, and financial and technical assistance are seen as the three major tools available to promote conservation. NRDC believes that BPA has the power to undertake many of the recommended actions within its existing authority, but it also promotes the concept of giving BPA more control and authority for the promotion of conservation and renewable resources.

State and local governments and utilities are also given a much expanded set of responsibilities. States should provide for research and development for alternative generation technologies and provide tax credits and other incentives for investments in those technologies. States and local governments should establish strict end-use regulatory standards for building codes, new electric hookups and conversions to electric heat. An audit program for commercial buildings and industries should be funded through an excise tax on businesses. Utilities can contribute by changing their rate structures and by offering technical and financial assistance to consumers for conservation and renewable resource programs.

e. Comparison of Scenario Impacts.

Table IV-45 compares the quantitative impacts of the five "worst-case" scenarios. The reader is once again reminded that values presented are in many cases tentative and subject to change. For the reasons given above the "Alternative Scenario" is not included in this comparison.

Unquantifiable impacts are difficult to compare; however, general conclusions can be reached regarding a few of these impacts.

Impacts of hydro development would be greatest under Scenario A and least under Scenario D, with the other three scenarios having identical impacts. The differences between the scenarios would be small compared to the overall magnitude of hydro development impacts.

Electrical transmission impacts would probably be greatest under Scenario A due to its reliance on numerous dispersed generating facilities. These impacts would probably be least under Scenario B, followed by Scenarios C, E, and D. Fuel transportation impacts would be greatest under Scenario C, followed by Scenarios E, D, A, and B.

Radiological impacts would be greatest under Scenario D, less under Scenarios E and C, and quite small under Scenarios B and A.

Air emissions risks to human health would probably be greatest under Scenario C, followed by Scenarios A, E, and B, with small impacts under Scenario D.

TABLE IV-45

IMPACTS SUMMARY
COMPARISON OF SCENARIOS A THROUGH E

Scenario Resources	Scenario A	B	C	D	E
Firm Peaking Capacity (MW)	23,039	23,233	23,074	23,220	23,170
Energy (ave. MW)	12,541	13,120	12,630	13,197	12,702
Impacts					
Land Use (acres)	459,000	152,000	57,000	12,560	29,100
Water Consumption (acre-feet/yr)	330,000	493,000	310,000	1.16×10^6	790,000
Water Emissions (tons/yr)					
Suspended/ Dissolved Solids	36.8	360	6,060	469,000	272,000
Inorganics	423	None	None	1,750	1,000
Organics	4.9	None	None	1,040	597
Other	771	771 $+2.14 \times 10^8$ gallons	None	None	None
Air Emissions (tons/yr)					
Sulfurous	113,000	20,900	95,400	86,200	87,900
Nitrous	212,000	27,200	359,000	22,800	159,000
Particulates	15,000	40,800	140,000	21,100	65,900
Hydrocarbons	101,000	8,480	18,000	264	7,190
CO	24,600	135,000	43,100	None	17,100
Other	1.62x106	541	None	None	None
Solid Waste (tons/yr)	1.67×10^6	1.33×10^6	8.86×10^6	5.46×10^7	3.49×10^7
Heat Releases ($\times 10^9$ Btu/yr)	1.19×10^6	196,000	657,000	954,000	814,000

f. <u>The Relationship Between the Scenarios and the Existing Hydro-Thermal System</u>.

The impacts of the resource scenarios as shown in the proceding section can be more fully understood by comparison with the hydroelectric and thermal resources which already supply power to the region. Regional resources in 1998, including the hypothetical scenario resources, are presented in Table IV-46 and Figure IV-8.

(1) <u>Impacts of Existing Hydro-Thermal Resources</u>.

The region's existing generating plants are shown in Figure IV-1.

The primary quantifiable impact of existing hydro resources is the land inundated by reservoirs. The land use impacts of regional hydroelectric facilities are shown in Table IV-44. In addition, hydro facilities have had significant, but unquantifiable impacts on the river ecosystem, particularly on anadromous fisheries. The impacts of hydroelectric development are discussed in Section IV.A.1.a.1.

Impacts of thermal power resources are divided into existing resources and those currently under construction. Impacts of existing resources are shown in Table IV-48, and impacts of resources under construction are presented in Table IV-49. In addition to the quantifiable impacts shown in the tables, thermal generation has impacts on air quality, human health, and visual resources. These impacts are discussed in Sections IV.A.1.a.b. and IV.B.2.d. of this chapter.

The summed impacts of Tables IV-47, IV-48, and IV-49 are shown in Table IV-50.

(2) <u>Comparison of Overall Impacts of Potential 1998 Regional Resources, Including the Existing Hydro-Thermal System and Hypothetical Resource Scenarios</u>.

Table IV-51 lists the overall impacts of 1998 regional resources, totalling the impacts of the existing hydro-thermal system as shown in Table IV-50 with the impact totals from the scenarios as shown in Table IV-45. Using this table, the reader can compare the effects of the different "extreme case" projections of regional resource development in context with existing hydro-thermal resources. The reader is again cautioned, however, that these tabulations are in no way intended as predictions, but are included for purposes of illustration only. Critical factors not considered here, particularly costs of the resources in the scenarios and technological developments which cannot be anticipated, make it exceedingly unlikely that actual regional resource development will take any of the courses discussed here. Development will most likely take a more moderate course than the extreme scenarios presented here. Impacts most likely will be correspondingly less severe than those of the scenarios.

Table IV-46

Contributions of Different Energy Resource Types to 1998 West Group Area Resources

Regional Resource Scenario	Status of Resource	Energy Output of Resource Type (Ave. MW or equivalent) Hydro	Conservation	Renewable	Coal	Nuclear	Total
A	Existing & Under Construction	12,037	198[2/]	--	2,458	5,416	20,109
	Committed	44	448	--	--	--	492
	Not Yet Planned[1/]	2,242	--	10,255	--	--	12,497
	Total	14,323	646	10,255	2,458	5,416	33,098
B	Existing & Under Construction	12,037	198[2/]	--	2,458	5,416	20,109
	Committed	44	448	--	--	--	492
	Not Yet Planned[1/]	771	11,511[3/]	390	--	--	12,672
	Total	12,852	12,157	390	2,458	5,416	33,273
C	Existing & Under Construction	12,037	198[2/]	--	2,458	5,416	20,109
	Committed	44	448	--	630[4/]	--	1,122
	Not Yet Planned[1/]	--	--	--	12,000	--	12,000
	Total	12,081	646	--	15,088	5,416	33,231
D	Existing & Under Construction	12,037	198[2/]	--	2,458	5,416	20,109
	Committed	44	448	--	--	3,822[5/]	4,314
	Not Yet Planned[1/]	--	--	--	--	9,375	9,375
	Total	12,081	646	--	2,458	18,613	33,798
E	Existing & Under Construction	12,037	198[2/]	--	2,458	5,416	20,109
	Committed	44	448	--	630[4/]	3,822[5/]	4,944
	Not Yet Planned[1/]	--	--	--	4,500	3,750	8,250
	Total	12,081	646	--	7,588	12,988	33,303

Notes

1/ Resources in this category are net scenario resources as shown in Tables IV-35, IV-37, IV-39, IV-41, and IV-43.

2/ Cogeneration.

3/ Includes end-use energy resources, which displace system electrical loads rather than providing power to the regional power system.

4/ Colstrip Units 3 and 4.

5/ Columbia and Pebble Springs Nuclear Plants.

FIGURE IV-8

PACIFIC NORTHWEST ELECTRIC ENERGY RESOURCE COMPOSITION

Existing Resources and Hypothetical Resource Scenarios

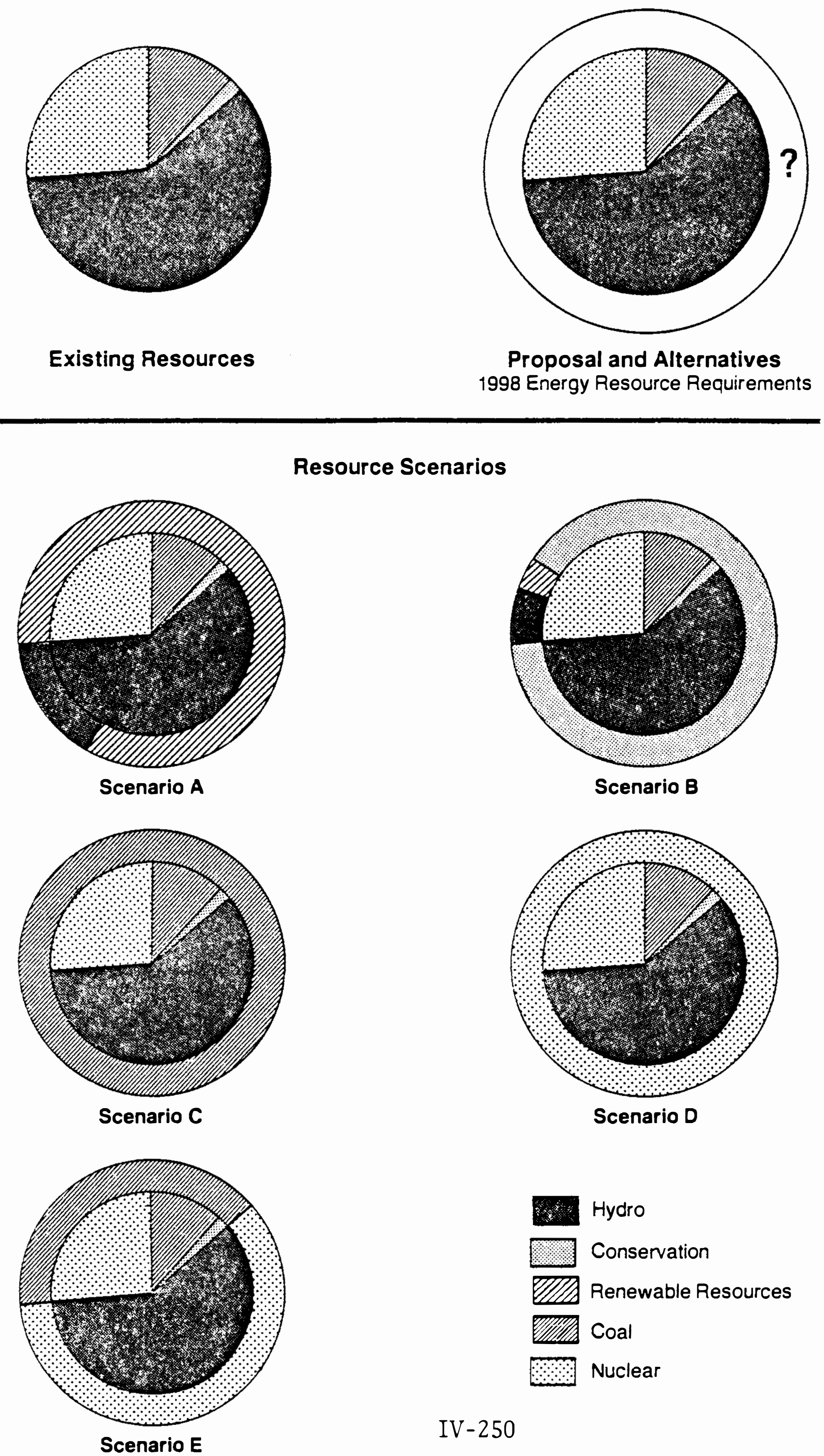


TABLE IV-47

LAND USE IMPACT OF THE EXISTING HYDROELECTRIC SYSTEM

Ownership of Project	Land Use Impact (acreage of reservoirs)
Federal 1/	455,843
Columbia River Treaty	202,060
Investor-Owned Utilities 2/	433,169
Publicly Owned Utilities	120,623
Total	1,211,695

Notes

1/ Does not include Libby Dam, a Columbia River Treaty project.

2/ Includes 112,000 acres for the Corra Linn project, owned by COMINCO, a private corporation.

TABLE IV-48

IMPACTS OF EXISTING THERMAL PLANTS 1/

	Colstrip 1 & 2	Centralia 1 & 2	Bridger 1, 2, & 3	Hanford G.P.	Trojan	Total of Existing Plants
Resource Output						
Firm Peaking Capacity (MW)	600	1,314	1,500	0	1,080	4,554
Energy (ave. MW)	494	920	1,050	515 2/	765 3/	3,744
Impacts						
Land Use (acres)	700 4/ +75/yr	200 +263/yr	14,800 5/ +125/yr	49	634 +155/yr	16,400 +618/yr
Water Consumption (acre-feet/yr)	9,700	6,900	29,200	-- 6/	68,900	115,000
Water Emissions (tons/yr)						
Suspended/ Dissolved Solids	238 7/	473	None	70.1 9/	28,500	29,300
Inorganics	None	None	None 8/	None	3,300	3,300
Organics	None	None	None 8/	None	Negligible	Negligible
Other	None	None	None 8/	None	None	None
Air Emissions (tons/yr)						
Sulfurous	26,600	41,000	53,800 10/	Negligible	5,240	127,000
Nitrous	15,600	68,000	32,200	Negligible	1,430	117,000
Particulates	3,230	55,000	5,640	Negligible	1,300	65,200
Hydrocarbons	343	1,030	780	Negligible	16	2,170
CO	1,200	3,470	230	Negligible	None	4,900
Other	None	None	None	None	None	None
Solid Waste (tons/yr)	347,000	754,000	616,000	None	3.35×10^6	5.07×10^6
Heat Releases ($\times 10^9$ Btu/yr)	32,100	41,200	60,600	48,100	48,600	231,000

Notes

1. Data is taken from environmental analyses for individual projects. Where project-specific data is unavailable, estimates have been made based on impacts of 1,000 MWe Pacific Northwest coal and nuclear plants as shown on page IV-182 above and in the Draft Role EIS, Part 1, Table V-55, page V-246.

2. Based on production of 4.5 billion kWh per year through April in 1978-79 through 1982-83.

3. Based on the capacity factor reported in the project-specific environmental analysis.

4. Estimated from land use for Colstrip Units 3 and 4.

5. Includes 14,000 acres for transmission line right-of-way.

6. Net water consumption of the HGP is essentially zero because once-through cooling is used. During operation, 423,000 to 564,000 gallons of water per minute is withdrawn from and returned to the Columbia River.

7. Does not include sedimentation due to mine runoff.

8. No discharge to surface waters.

9. Based on a plant capacity factor of 60 percent.

10. The lower-limit estimate for this type of emissions was 25,200 tons/yr.

TABLE IV-49

IMPACTS OF THERMAL PLANTS UNDER CONSTRUCTION 1/

	Bridger 4	Boardman (Carty Coal)	Colstrip 3 & 4	WNP 2	WNP 1 & 4	WNP 3 & 4	Total of Plants Under Construction
Resource Output							
Firm Peaking Capacity (MW)	500	530	1,400	1,100	2,500	2,480	8,510
Energy (ave. MW)	350	398	1,050	701	1,725 2/	1,711 2/	5,304
Impacts							
Land Use (acres)	10 +75/yr	3,920 4/ +263/yr	6,700 5/ +125/yr	1,110	35 6/ +360/yr	2,140 +358/yr	13,900 +1,050/yr
Water Consumption (acre-feet/yr)	5,650	18,100	26,000	78,500 8/	164,000 8/	133,000 8/	426,000 8/
Water Emissions (tons/yr)							
Suspended/ Dissolved Solids	None 3/	None 7/	None 7/	29,040 9/	66,000 9/	65,500 9/	65,500 9/
Inorganics	None 3/	None 7/	None 7/	124	624	3,320	4,070
Organics	None 3/	None 7/	None 7/	None	None	None	None
Other	None 3/	None 7/	None 7/	None	None	None	None
Air Emissions (tons/yr)							
Sulfurous	3,070	21,500	3,320 10/	5,340	12,100 10/	12,000 10/	57,300 10/
Nitrous	10,700	12,800	23,400	1,460 10/	3,300 10/	3,280 10/	55,000 10/
Particulates	996	4,700	3,780	1,320 10/	3,000 10/	2,980 10/	16,800 10/
Hydrocarbons	260	636	28	16.3 10/	37 10/	37 10/	1,010 10/
CO	77	1,560	164	None	None	None	1,800
Other	None	None	None	None	None	None	5.6
Solid Waste (tons/yr)	333,000	109,000	736,000	3.41×10^6	7.75×10^6	7.69×10^6	2.00×10^7
Heat Releases ($\times 10^9$ Btu/yr)	19,400	23,200	68,100	52,300	103,000	107,000	373,000

Notes

1. Data is taken from environmental analyses for individual projects. Where project-specific data is unavailable, estimates have been made based on impacts of 1,000 MWe Pacific Northwest coal and nuclear plants as shown on page IV-182 above and in the Draft Role EIS, Part 1, Table V-55, page V-246.

2. Based on the capacity factor reported in the project-specific environmental analysis.

3. No discharge to surface waters.

4. Includes 6,000 acres for transmission line right-of-way.

5. Includes 1,540 acres for transmission line right-of-way.

6. Acreage for the WNP 1 and 4 plant sites is included under land use for WNP-2.

7. No normal discharges to natural bodies of water or to groundwater.

8. For nuclear plants includes water consumed at enrichment plant.

9. Solids for nuclear plants are concentrated from river water by cooling towers.

10. Gaseous discharges are primarily by the coal-fired generation powering the gaseous diffusion enrichment plants.

TABLE IV-50

CUMULATIVE IMPACTS OF THE
EXISTING HYDRO-THERMAL SYSTEM AND
THERMAL PLANTS UNDER CONSTRUCTION 1/

	Hydro System	Existing Thermal Plants	Thermal Plants Under Construction	Total of Thermal Resources	Total of Hydro-Thermal Resources
Resource Capability					
Firm Peaking Capacity (MW)	29,505 2/	2,724 2/	7,450 2/	10,174 2/	39,679 2/
Energy (ave MW)	12,037 2/	2,450 2/	5,165 2/	7,615 2/	19,642 2/
Impacts					
Land Use (acres)	1,210,000	16,400	13,900	30,300	1,240,000
Water Consumption (acre-feet/yr)	None 3/	115,000	426,000	540,000	540,000
Water Emissions (tons/yr)					
Suspended/ Dissolved Solids	None	29,300	161,000	190,000	190,000
Inorganics	None	3,300	4,070	7,400	7,400
Organics	None	Negligible	None	Negligible	Negligible
Other	None	None	None	None	None
Air Emissions (tons/yr)					
Sulfurous	None	127,000	57,300	184,000	184,000
Nitrous	None	117,000	55,000	172,000	172,000
Particulates	None	65,200	16,800	81,900	81,900
Hydrocarbons	None	2,170	1,010	3,190	3,190
CO	None	4,900	1,800	6,700	6,700
Other	None	None	5.6	5.6	5.6
Solid Wastes	None	5.07×10^6	2.00×10^7	2.51×10^7	2.51×10^7
Heat Releases ($\times 10^9$ Btu/yr)	None	231,000	373,000	604,000	604,000

Notes

1. Includes impacts of resources. For example, impacts of the Jim Bridger coal-fired generating plants, which do not serve West Group Area loads, but do serve other loads within the Pacific Northwest, are included in order to provide complete coverage of the impacts of regional resources.

2. Capacity and energy figures listed are for resource output committed to West Group Area loads. Adjustments are necessary to determine total West Group Area resources.

3. Does not include loss due to evaporation from reservoir surfaces.

TABLE IV-51

COMPARISON OF SCENARIOS INCLUDING THE EXISTING HYDRO-THERMAL SYSTEM

Scenario Resources	Existing Hydro-Thermal System	Total of Scenario Plus Existing System				
		A	B	C	D	E
Firm Peaking Capacity (MW)	39,679	62,718	62,912	62,753	62,899	62,849
Energy (ave MW)	19,642	32,183	32,762	32,272	32,839	32,344
Impacts						
Land Use (acres)	1,240,000 +1,670/yr	1,700,000 +1,770/yr	1,390,000 +1,750/yr	1,300,000 +2,770/yr	1,250,000 +2,650/yr	1,270,000 +2,680/yr
Water Consumption (acre-feet/yr)	540,000	870,000	1,030,000	850,000	1,700,000	1,330,000
Water Emissions (tons/yr)						
Suspended/ Dissolved Solids	190,000	190,000	190,000	196,000	659,000	462,000
Inorganics	7,400	7,820	7,400	7,400	9,150	8,400
Organics	Negligible	4.9	Negligible	Negligible	1,040	597
Other	None	771	771	None	None	None
Air Emissions (tons/yr)						
Sulfurous	184,000	297,000	205,000	279,000	270,000	272,000
Nitrous	172,000	384,000	199,000	531,000	195,000	331,000
Particulates	81,900	96,900	123,000	222,000	103,000	148,000
Hydrocarbons	3,190	104,000	11,700	21,200	3,450	10,400
CO	6,700	31,300	142,000	49,800	6,700	23,800
Other	5.6	1.62×10^6	547	5.6	5.6	5.6
Solid Wastes	2.51×10^7	2.68×10^7	2.64×10^7	3.40×10^7	7.97×10^7	6.00×10^7
Heat Releases ($\times 10^9$ Btu/yr)	604,000	1.79×10^6	800,000	1.26×10^6	1.56×10^6	1.42×10^6

C. BPA's Ability to Affect the Regional Resource Mix.

1. Introduction.

Chapter III describes the BPA proposal in terms of eight separate activity areas, namely, customer services, transmission planning, power planning, conservation, sources of power, sales, rates, and public involvement. Also described are the complementary elements of the regional structure, grouped under the headings of utilities and direct-service industries, State and local government, and cooperative arrangements. Each of the four alternatives is similarly described under the headings of the eight activity areas and the three elements of the regional structure.

Chapter IV addresses the environmental consequences of the regional power system as it exists today and as it might develop in the future. Section A evaluates the environmental impacts of the regional power system as it exists today, including the plants which are under construction. This serves as a baseline for evaluation of the impacts of alternative ways the region might move in the future. This includes an analysis of the effects of regional cooperation and coordination, load-resource imbalances, and nonpower issues; an analysis of the generic impacts of various forms of conservation, different forms of renewable resource generation, storage technologies, conventional thermal generation, and unconventional resources; and an analysis of the impact of five hypothetical future resource scenarios. The scenarios take as their starting point the energy loads and the peak loads forecasted for the West Group area of the Northwest Power Pool by the PNUCC in March and April 1979. The scenarios describe five different mixes of resources by which the region hypothetically might meet these loads and discusses the environmental impacts of each of the five mixes.

All of the scenarios include a 448 megawatt reduction in loads as projected in the PNUCC forecast of firm energy loads set forth in Table IV-32, resulting from conservation based on residential weatherization efforts and the application of residential solar space and water heating in the region. The 448 MW reduction in West Group Area loads is derived from the PNUCC econometric model, which is independent of, but is used to verifty, the PNUCC West Group Area forecast. The 448 MW figure was developed by comparing the results from the model with and without factors for conservation. The same amount of load reduction is included in all of the scenarios in that they are all based on the same forecast, but it must be explicitly accounted for in Scenario B to avoid double counting, because the conservation potential used in the scenario includes the measures already assumed to be in effect in the forecast.

All five scenarios also assume that some of the conventional hydro projects considered most likely to be developed prior to 1999 will be constructed. Scenario A assumes that one hundred percent of the additional load will be served from new renewable resource generation; Scenario B assumes maximum conservation efforts; Scenario C assumes the additional loads will be met one hundred percent by coal-fired generation; Scenario D, that the loads will be met by nuclear generation; and Scenario E assumes a mixture of coal-fired and nuclear generation.

In considering the environmental impacts of the BPA proposal and the alternatives, it is appropriate to analyze the extent of BPA's ability to affect the regional resource mix under existing statutory authority and alternatives. The analysis which follows relates the activity areas described in Chapter III to the possible alternatives for future development described in Section B of Chapter IV.

The first element of the analysis describes the factors which might reduce loads. The five regional resource scenarios are based on the load forecasts of PNUCC. If loads in fact are less than this, then the generation resources necessary to meet load will be less and the environmental impact from generation resources will be less. The other elements of the analysis are the factors that affect the use of conventional thermal generation and the factors that promote the use of renewable resource and other alternative generation. In all cases it must be recognized that there are external factors over which BPA has no control which affect the results. A few of the BPA activities directly affect either load reduction or generation, although most of their activities have only an indirect effect.

Section D of Chapter IV analyses the impacts of the BPA proposal and alternatives, and Section E summarizes and compares the impacts of the BPA proposal and alternatives and relates them to the five "worst case" scenarios.

2. Factors That Reduce Loads.

a. External Factors.

In order to evaluate BPA's ability to indirectly influence the amount of conservation practiced in the region, it is necessary to have, as a baseline, knowledge of how much energy is already being conserved. While the magnitude of conservation accomplished to date is not known with any degree of precision, there is reason to believe that annual energy consumption in the region currently is roughly 5 to 10 percent less than it would have been without conservation. This rough estimate is based on consideration of the following factors.

In the 1970's, the region experienced a recession, a number of industrial strikes, a short-term fuel shortage, two severe droughts, and high rates of inflation. In addition, it entered into an age of high-cost thermal electric energy. All of these conditions produced large increases in the cost of electricity to ultimate consumers and tended to suppress the rates of growth in energy consumption relative to earlier periods. In addition to the conservation induced by increases in the cost of energy, there has also been a heightened awareness of the need for conservation, which in turn has produced additional voluntary reductions in energy use. The net effect of these conditions has been to reduce long-term compound rates of annual growth from the 7 percent level of the 1960's to about a 4 percent level in the 1970's. It is virtually impossible, however, to isolate how much of this reduction is due to conservation as a result either of higher energy prices or of specific Federal, State, or utility conservation programs.

The factors which have lead to reduced consumption in recent years can be expected to continue into the future irrespective of BPA's activities. Higher prices and keen awareness of national energy shortages will continue to act as a spur. Also, if the region experiences brownouts and curtailments because generation has not kept pace with demand, consumers will be motivated to reduce their reliance on the constant availability of electric service.

In addition there are a number of Federal and State programs to promote conservation which are discussed at pages IV-60-65. The effectiveness of these programs to reduce loads is still speculative.

b. BPA Activities Having Direct Effect.

The only activities BPA has determined it could engage in under its existing authority which directly reduce energy loads are the internal conservation efforts BPA might make on its own system and the pilot conservation programs which it is currently undertaking. Under Alternatives 1 and 2 even the pilot programs would be eliminated. Under Alternatives 3 and 4, however, BPA would be given broadened authority to finance and undertake, itself or through regional utility systems, substantial conservation efforts in the form of insulation and weatherization of homes and buildings, installation of solar water heaters and other end use solar devices, and so forth. Conservation would be treated as a resource in which BPA could invest, and BPA would be mandated to engage in all cost effective conservation efforts before acquiring generation from renewable resources or from thermal resources. The data is not available to estimate with any precision what the results of such a program might be. However, rough estimates of what the total accomplishment for the region might be are described in pages IV.B.2.a.

c. BPA Activities Having Indirect Effect.

(1) Loads of Direct-Service Industries.

Under existing statutory authority, because the direct-service industrial customers (DSIs) are not preference customers and because the demands of the preference customers will exceed the supply available to BPA, BPA has no choice but to allow the contracts with the DSIs to expire at the end of their term and to reallocate the power among preference customers. This would happen under the BPA proposal as well as under Alternatives 1 and 2. Under Alternatives 3 and 4, however, BPA would be authorized to acquire additional resources to meet the DSI loads as well as the preference customer loads.

As discussed in Chapter III, when existing DSI contracts expire, DSIs would have four options regarding Northwest operations: apply for service from utilities in or near whose service area the industries were located; make arrangements to purchase resources elsewhere and seek transmission services from the Federal system and/or regional utilities; construct their own generating resources, either individually or as a group; or cease operating in the region.

Acquisition of a substitute power supply would not of itself affect the efficiency of the industry operations. However a substantial increase in the price of electric energy might induce the industry to improve efficiency. Northwest aluminum producers have joined in an industry-wide commitment to reduce per-unit energy usage 20 percent below the 1972 level by the end of 1985. This new commitment doubles the goal established in 1974 as part of the joint government-industry energy conservation program. The initial commitment of the voluntary program was to shave 10 percent from 1972 requirements by the end of 1980; this milestone was accomplished 2 years ahead of schedule in the second half of 1978.

Current examples in the Northwest include multi-million dollar technological conversion projects at several reduction plants, including introduction of the Sumitomo modifications at the Martin-Marietta plants in Goldendale, Washington, and The Dalles, Oregon; and at the Anaconda plant in Columbia Falls, Montana. Other programs and methods are being introduced at Kaiser and Reynolds facilities. These conservation and efficiency measures will not reduce regional loads but will allow the industries to produce more product with the same amount of power. Under the current contracts, the industries are entitled to receive a stated contract demand. BPA does not have the ability to reduce this contract demand due to efficiency improvements.

Future improvements in energy consumption figures for the industry could come in the form of new technologies currently under development, including the ALCOA process which utilizes a chlorine conversion technology, and others in the development stage. However, there is still significant research and development to be done before those technologies prove themselves commercially viable. For the most part, it will not be possible to utilize these improvements at existing plants--rather, they would be applied at new facilities.

In the areas of economic and environmental impacts, the critical question is not so much who serves the industries, but whether or not they operate in the region. The impacts discussed in Section IV.A.2.e. of this chapter would continue if the plants could be served.

If the firms were not able to obtain electric power in the amount or at a price that would allow continued economic operations in the region, the resulting impacts from plant shutdown would vary widely depending upon the local area in which the plant was located. Economically, the impact would be primarily dependent upon the importance of the plant and associated employment to the local economy. The DSI customers of BPA are an important and integral segment of the economies of Washington, Oregon, and western Montana. However, the specific importance of the customers to local economies varies substantially within the region. Plants sited in urbanized counties with diversified economies would have a significant but not critical impact. Workers unemployed by plant shutdowns in these areas could be absorbed into the local work force, presumably reemployed at other neighboring industries. The duration of individual worker unemployment would depend upon local conditions at the time of plant shutdown and is impossible to predict at this time.

However, many of these plants are sited in rural communities where the facility is the main industrial activity. The DSI customer in this economic setting is often the principal component of employment and income, and frequently the main tax source for public services in the area. Closing such facilities would place a severe economic burden on these small communities.

In 7 of the 16 counties in which DSI plants are sited, these plants directly and indirectly represented between 19 and 50 percent of the total county economy in 1975. Impacts approaching 20 percent of all employment in a local area must be assumed to bear significantly on the local economic base. Also, communities with the most significant impact from the direct-service industries generally have populations of less than 50,000. If the plant workers were unemployed, they would likely leave the community to find comparable employment, therefore reducing area population and undermining the economic structure of the area. Spinoff impacts in the form of a decreasing tax base and underutilization of community facilities as population declined would be experienced. The region's DSIs currently supply one-third of the nation's primary aluminum, 9 percent of the nation's supply of primary nickel (the total national output), and from 10 to 15 percent of the requirements for crude silicone carbide abrasive. Closing the regional DSIs would have significant impacts on the nation's aluminum markets and prices, and on silicone carbide markets. To rebuild the regional primary aluminum capacity in another area of the nation would require an investment in excess of three billion dollars at today's replacement costs.

Environmentally, the impacts of a DSI's decision to close down would be positive for the region. Air pollution loadings in any of the areas where plants were sited would be reduced, with the most significant impacts in those areas where the plants were major contributors in the local airshed and where air quality standards were being exceeded. However, in no instance would plant shutdown alone allow the achievement of National Ambient Air Quality Standards. The same would true in the areas of water quality, terrestrial environment, health effects, and impacts on endangered species. After a period of time of non-operation, the local environment might return to pre-plant status, although other industry might have developed in the area in the meantime.

Impacts on the power system are determined by who serves the DSIs. If the industries were not served through the Federal power system, i.e., from BPA or through preference customers, the services they provided (as discussed in Section IV.A.2.e.(3) of this chapter) would be lost to the total system, including operating reserves, forced outage reserves, and a safety margin against plant delays. If the power now committed to the direct-service industries were contracted through a utility or utilities, these services would have to be supplied through alternatives such as combustion turbines, a lower percentage of firm power being contracted, construction of more units for supplying capacity or perhaps through alternative contracts for the quality of power currently provided to the DSIs.

If the DSIs provided their own power, either independently or through a group of utilities not dependent on the Federal system for this energy, these resources would be available to certain portions of the region. It is not possible to predict specific impacts from this arrangement due to the uncertainties in its formation, terms, etc.

(2) Other BPA Activities.

The range of other activities available to BPA under its existing statutory authority holds the potential for influencing the reduction of electric power loads in the region through persuading and inducing consumers to conserve electricity, but it is impossible to quantify the extent of this influence. These activities include the education and technical assistance efforts that are currently a part of BPA conservation program. In power planning and transmission planning, BPA can assist in documenting the effectiveness of conservation efforts, allowing it to be incorporated in to load forecasts on a long-term basis. Forecasts are not revised in response to short-term changes in demand but must reflect realistic long-term needs.

With respect to rates, existing statutes require that the overall revenue level be limited to that which is necessary to recover costs; however, in designing rates within this limit, BPA may consider actions which might encourage conservation. For example, in designing the rates which went into effect on December 20, 1979 on an interim basis, the revenues from the value of service or share-the-savings rate for the sale of nonfirm energy (Schedule H-6) and the revenues from the sale of firm capacity (Schedule F-7) which were in excess of allocated cost were used to eliminate the off-peak capacity charge and to reduce the summer capacity charge in Schedules EC-8, IF-2, and MF-2. This action incorporates the proper price signal that future energy costs will increase at a much faster rate than future capacity costs, and may therefore encourage the conservation of energy.

BPA is investigating the feasibility of various conservation rate alternatives in the development of its 1981 wholesale rate proposal. Included in these alternatives is the consideration of a baseline rate at the wholesale level which could be passed on to residential consumers as well as a conservation rate incentive for aluminum companies intended to serve as an inducement for increased operating efficiency. In the latter case BPA could tie the rate charged to the amount of aluminum produced per unit of energy consumed.

With respect to allocations, BPA proposed that 15 percent of its total firm energy resources would be included in a conservation reserve to be allocated to customers which undertake approved conservation programs. Under this provision, an approved conservation program is one which increases the efficiency of generation, decreases electrical line losses, or one which otherwise decreases the region's dependency upon central station generation. Included in this last category would be any program designed to implement renewable resource applications. BPA is investigating the possibility of an energy surcharge to those utilities that do not develop a conservation program.

The possible environmental impacts of the allocation proposal are being examined in a study which is now underway. This analysis will consider whether the proposed conservation reserve will have a stimulating or inducing effect upon the preference agencies to undertake conservation programs which they might not do otherwise, and whether a larger reserve would be effective and feasible.

BPA is only one of the forces working in the region to promote conservation. The cumulative impact of all of its efforts indirectly to foster and encourage conservation under its existing statutory authority is necessarily limited. Available information on the potential for total energy savings in the region is discussed on pages IV-117-122. The findings of the Skidmore, Owings, & Merrill (SOM) study on this subject are summarized in Table IV-16. The first column shows the possible savings resulting from educational programs. The BPA indirect activities would fall in this category and would only be a minor part of these efforts. The incentives which BPA might provide through rate and allocation policy are of a different character from the incentive programs discussed in the SOM report that are included in the second column. BPA, of course, currently has no authority to implement mandatory requirements, which are cumulated in the third column of the SOM table.

The estimates of total potential energy savings shown in Table IV-16 reflect, in part, the effect of BPA educational programs which have been developing since 1974. However, for a number of reasons, the precise effect of BPA efforts cannot be estimated accurately in quantitative terms. First, although the figures presented in Table IV-16 continue to be the best available for the BPA service area, they were prepared in 1976 when little information was available about energy conservation measures, thus some generalizations were necessary, such as the assumption that none of the region's buildings were insulated prior to 1975. This assumption and others are likely in error, and most of the information used is now out of date. Better data is under development. Second, BPA efforts have been augmented by related efforts by utilities and independent programs of municipalities, States, and other Federal agencies. Other programs, not just educational, but including incentives such as tax credits, or mandatory requirements such as building insulation standards, have also been instituted, and these programs obscure the effect of educational programs like BPA's. Furthermore, the considerable increases in energy prices in recent years and the likelihood of continued increases in the future have stimulated awareness and conservation activity among consumers which may have occurred regardless of the many conservation programs now in effect.

The difficulty involved in establishing a quantitative estimate of the effect of BPA conservation programs does not mean that these programs have not been effective in motivating conservation of energy. It simply means that the effect cannot be distinguished from the effects of other programs. An undocumented guess at the effect of BPA programs, which must be understood to have a wide margin of error, would be that BPA's efforts have achieved perhaps a tenth of the total potential savings with educational programs. The actual effect could be anywhere between one-fifth and five times this estimate.

3. Factors That Affect Conventional Thermal Generation.

a. External Factors.

In the region, there are currently under construction five nuclear powerplants, two coal plants (Table IV-3), seven Federal hydro plants or plant additions (Table IV-1), and two non-Federal hydro plants (Table IV-2). There are external factors unrelated to the proposal or alternatives which could cause cancellation or delay in the construction programs of these plants. National policy with regard to environmental and safety issues might result in shutdowns of specific types or designs of generating facilities or more stringent operating standards, which could in turn make it technically or economically impossible for a powerplant to operate. Project sponsors could also be forced to abandon or delay construction because of their inability to secure continued sources of funding, particularly when bonds must be approved by voters.

The future of powerplants which are planned but are not under construction and plants which are not yet on the drawing boards is even more uncertain. Every major aspect of a new project is controversial--need, technology, fuel, site, environmental impact, cost, financing, and the licensing or certification process. The uncertainty declines, of course, the farther along the plant is in the planning and licensing process. Thus, it is more likely that units will be added to existing projects, such as Colstrip units three and four, than that completely new projects will be built, because for the existing projects many problems already have been solved, such as site selection, fuel supply, and power transmission. A plant which has undergone siting council hearings may not be subject to reevaluation prior to initiation of construction even though planning factors may change during the licensing process.

If BPA does not receive the additional authority under Alternatives 3 and 4 to promote the one-utility approach to regional power management, the utilities in the region will be forced increasingly to go their separate ways in attempting to find resources to meet loads. As each utility plans individually to meet future loads, the risk of overbuilding increases, based on uncertainty of future Federal power allocations, load forecasts, plant construction schedules, effectiveness of local conservation programs, the economic impacts of underbuilding, and general conservatism related to public utility responsibility. Without a coordinated regional approach to buffer individual utilities through regional "sharing" of the shortage potential, utilities must provide a larger safety margin in their own resource schedules, which results in the impacts of construction and operation of facilities or the impacts of deficits due to reduced firm power capability.

The potential for underbuilding in these alternatives must not be dismissed, however. If a utility decides to rely on a particular technology, and the approach in its individual area is not successful, time will generally not remain to build other new resources. This could result in a shortage. In addition, generating facilities will continue to be more difficult for single utilities or small groups to finance, due to high capital costs and construction uncertainties.

b. <u>BPA Activities Having Direct Effect</u>.

BPA does not have existing statutory authority to construct conventional thermal generating plants nor is it proposed in the pending legislation discussed under Alternative 3 to give BPA such authority. Under Alternative 4 BPA would be authorized under some circumstances to construct thermal generation.

The other way by which it could be said that BPA directly brings about the construction of new conventional thermal generating plants is by entering into long-term contracts to acquire the output or a portion of the output of the plants and to reimburse the plant owner for its total construction, financial and operating costs. The Congress gave special authorization to BPA in the Appropriation Acts for fiscal years 1969 and 1970 to enter into such contracts, utilizing net-billing as the means of payment, for some of the plants included in the Hydro Thermal Power Program Phase 1. These plants are the city of

Eugene's 30 percent share of the Trojan Nuclear Plant constructed by Portland General Electric, 100 percent of WPPSS Plants Nos. 1, 2, and 70 percent of WPPSS Plant No. 3. BPA does not have authority under existing law to enter into such contracts for other plants. Phase 2 was erected on the basis that BPA would act as agent for others in the sale and purchase of the output of the new plants, but would not purchase and resell the output in its own name. Although BPA still has the authority to enter into long-term trust agency contracts, the regional consensus upon which Phase 2 rested no longer exists.

The pending legislation which is discussed under Alternatives 3 and 4 would give BPA broad new authority to acquire the output of conventional thermal generating plants subject to strict conditions of planning, priority, and evaluation.

c. <u>BPA Activities Having Indirect Effect</u>.

(1) <u>General</u>.

BPA has authority to engage in a broad array of activities which are of considerable value to entities which wish to construct conventional thermal generation plants. Of particular importance are the provision of reserves, load factoring, trust agency, and other customer services; the sale of peaking capacity and nonfirm energy; and the wheeling of the output of the plant over the BPA regional high voltage transmission grid.

Under the BPA proposal, in the promotion of the one-utility concept, BPA would cooperate with the utilities which construct new conventional generating plants. It would offer to provide transmission for the output of the plant and would, if the offer is accepted, include the necessary transmission facilities in its planning and construction program. It would include the new plants in the forecast of regional resources and would undertake to provide integration services to the extent supplied to other plants. It would sell the plant owners peaking capacity and nonfirm energy, subject to preference requirements and allocation policies, and would provide them a variety of customer services, except long-term trust agency services.

Apart from these services, BPA's rate for nonfirm energy could affect a utility's decision with respect to the type of generation it constructed, particularly with the present energy supply situation in the Pacific Northwest. BPA and other Northwest utilities are finding it difficult to meet growing loads by relying on the timely completion of planned central station coal and nuclear plants. This may produce a regional resource deficit. Part of the deficit could be met by reducing demand through conservation, but the remainder of the deficit would have to be made up by other resources or some curtailment of load would be necessary. The possibility of a regional deficit has led BPA and others to examine alternatives which include the economic feasibility of meeting loads with a combination of nonfirm energy and generation plants with low investment costs and high operating costs, such as combustion turbines which burn oil and gas.

The attractiveness of the combustion turbine alternative depends upon the rate for the availability of BPA's secondary energy, the cost of fuel for the turbine, and a number of hours that the turbine would be required to operate. Therefore, the lower the rate for secondary energy, the more incentive there would be to reevaluate operational and planning criteria to find means for more intensive use of nonfirm energy in the Northwest. That is, low rates for nonfirm energy would encourage utilities in the Northwest to develop generation plants with low investment costs and high operating costs. Conversely, high rates for nonfirm energy would encourage the development of more capital intensive generation plants such as renewable resources, coal generation, and nuclear generation.

Similarly, BPA's allocation policy could influence customer decisions regarding the construction by those customers, if any, of new generation or certain kinds of generation. For example, in the proposed allocation policy which BPA published in October 1979 for public comment, BPA proposes (1) that its customers must first use to meet their own loads all assured resources owned or acquired by them which have a resource cost equal to or less than the resource cost of BPA firm energy; and (2) that those lower cost resources will be deducted from their total requirements to arrive at a net energy requirement which is eligible for allocation. On the other hand, resources with a cost greater than that of BPA firm energy, can be used in the customer's own system, if needed, or offered for sale at cost, plus a reasonable rate of return, first to BPA and then to other Pacific Northwest preference customers or other Pacific Northwest utilities. This may have the effect of encouraging the construction of alternative and renewable energy resources and the dedication of such new, possibly higher cost resources, to regional loads. Such sales would not affect the customer's allocation and could if purchased by BPA to meet contractual requirements be sold at a melded rate comparable to other BPA energy.

(2) Effect of BPA Not Providing Services.

If BPA did not provide the power, transmission, and other customer services in whole or in part, regional resource development would not stop. Regional utilities can and will provide generation as they do in the rest of the nation acting either jointly or individually.

BPA, during Phase 2 of HTPP, had as one of four proposed contractual arrangments the offer to act as a trust agent for participants in the development of new resources. BPA's offer of services was rather comprehensive. It included an offer to identify needs, to assist the utility in financial arrangements for the development of resources, to oversee the process of construction, upon completion of the resource to schedule those resources, to balance surpluses and shortages among the principals and to attempt to either sell surplus energy or to buy energy where a shortage had ensued. The offer under trust agency was comprehensive except that BPA would not at any time undertake the construction of any resource or pledge the resources of the Federal system in aid of financing construction.

BPA could still enter into such long-term trust agency agreements. However, the political climate is different today and the need for such a service is no longer perceived by most of the utilities. Recently, many small cooperatives have joined together in arrangements, similar to a trust agency relationship, called the Pacific Northwest Generating Company, and the Northwest Energy Service Company which are both cooperative utility efforts formed for the sole purpose of providing generation sources. In the trust agency proposal, BPA's offer was to act as an agent. Without a principal, there can be no agent and there are no principals requesting this kind of service from BPA at the present time. It is unlikely, whatever BPA might be willing to do, that there would be a sufficient utility interest to bring about a trust agency relationship. Among the reasons for this are the utilities' desire for a more localized control, the increasing problems of constructing any new resource and the obvious difficulties dependent upon financial management and construction costs in the 1980's. A review of possible impacts upon the development of resources under some hypo- thetical trust agency relationship becomes idle speculation in face of the foregoing realities. Thus, unless and until the industries or other customers submit a legitimate proposal, BPA does not propose or plan a role as Administrator of long-term trust agency agreements.

Without BPA, <u>peaking capacity</u> now planned to be provided by Federal hydro facilities would probably be replaced by a combination of inter-utility cooperation in utilizing peak load diversities and existing non-Federal hydro facilities; construction of peaking generation, i.e., combustion turbines or pumped storage; and increased load management. To the extent they were effective, utility cooperation and load management would provide for lesser environmental impacts. [See Sections IV.B.1.a.(3). (diversity exchange) and IV.B.2.a.(2). (load management). Environmental impacts of generating systems are covered in Section IV.A.1.a.(1)]

It is not possible to predict precisely how future peaking impacts of the power system would evolve without additional Federal hydro facilities unless it is known specifically what resources would be substituted. It can be anticipated that air quality would be significantly impacted on a localized basis due to increased operation of combustion turbines. Impact shifts from Federal hydro peaking to non-Federal hydro would also be probable. All of these could be mitigated by the implementation of load management programs to reduce the need for peaking power.

In order to market the output of the widely scattered Federal projects, BPA constructed long-distance high-voltage <u>transmission</u> lines. As a natural consequence, BPA assumed the regional role of providing the major backbone transmission system which effectively integrated all of the electric generation utilities in the United States portion of the Columbia River Basin. It is highly unlikely that this integration would be terminated under any circumstances due to system reliability and efficiency benefits. If BPA did not continue to fill this role, the utilities would. The outcome of this shift would be twofold. First, without additions to the Federal Columbia River Power System (FCRPS), future transmission needs would be met with more limited purpose lower voltage lines constructed with higher associated impacts and increased costs. Second, plants would potentially be sited closer to load centers to reduce transmission costs. Depending on the circumstances, this may or may not affect the resource technology chosen for construction.

Sales of surplus power, scheduling, and other regional activities in which BPA is a participant would also continue, undoubtedly with some loss of efficiency. However, in the areas of load factoring and load growth reserves BPA has a more significant role.

For load factoring, one alternative would be an agreement among utilities owning capability of a number of thermal plants. The group would coordinate its own loads and resources prior to contracting for a single load factoring service from BPA. Thus, customers could take full advantage of the capabilities of their own generation and reduce the load factoring service needed from BPA. (This form of thermal coordination agreement, providing for coordinated scheduling among utilities of thermal plant output, is discussed in detail in Appendix A of the Draft Role EIS).

Another alternative to BPA providing load factoring service would be for utilities that own thermal plant capability to enter into bilateral arrangements for service with utilities that have hydro generation and available reservoir storage. This alternative is limited by the number of utilities that have the capability to provide load factoring service, and by the fact that it excludes BPA, which through operation of the Federal Columbia River Power System, has one-half of the region's hydroelectric capability and a major part of the storage.

If BPA did not provide load factoring services, one of the capabilities of the Federal hydro system would be wasted. The customers would have to provide their own load factoring service requirements by (1) varying their own baseload generation, with consequent loss of firm load-carrying capability, when constant output may be more desirable from cost, equipment maintenance, and environmental impact standpoints; and (2) constructing or purchasing power from additional pumped storage, or peaking or intermediate load thermal plants.

If BPA did not provide load growth reserves to meet the utilities' unanticipated load growth, the utilities would have three basic alternatives. The first alternative would be to secure firm resources annually from other utilities in amounts sufficient to meet energy or capacity deficits resulting from unanticipated load growth. The ability to purchase sufficient amounts to cover deficits would be dependent upon the availability from other generating utilities of energy or capacity which had been determined in advance of the operating year to be surplus. The amount of energy and capacity available in advance of the operating year may affect the rate utilities would pay for this capacity and energy. If firm capacity and energy to meet forecasted deficits were unavailable in advance of an operating year, due to unanticipated load growth, some utilities, unable to acquire firm resources to eliminate their deficit, might start the operating year with a forecasted deficit. If nonfirm energy or surplus capacity became available during the year, such utilities would then be able to meet their firm loads with non-firm energy or surplus capacity. If nonfirm energy or surplus capacity did not become available during the operating year, utilities with deficits would have insufficient resources to meet their firm energy or capacity requirements.

Regional utilities have the second alternative of constructing generating facilities, or purchasing generating project output under long-term arrangements in amounts which would provide sufficient resources above their forecasted loads to provide a margin for unanticipated load growth. Utilities electing this option would have sufficient resources to avoid deficits resulting from unanticipated load growth. To the extent that such resources are estimated in advance of the operating year to be surplus to the utilities requirements, the owner utility could sell surpluses to utilities having a load-resource deficit. If such surplus resources could not be sold in advance of an operating year, the utility would attempt to dispose of the output from these resources as surplus energy or capacity during the operating year, perhaps at a rate insufficient to recover the cost of generation. If the cost of such resources could not be recovered, the cost of such resources would be absorbed by the owner utility, to the extent that cost could not be mitigated by reduced operation.

If BPA does not make load growth reserve energy and capacity available, the third option available to a utility in need of load growth reserves would be to enter into an arrangement with other utilities to pool their resource surpluses and deficits in advance of an operating year, balancing surpluses and deficits of participating utilities, and thereby attempting to reduce each participating utility's projected surplus or deficit of resources. This arrangement would have the advantage of providing each participating entity with an equal opportunity to secure resources to reduce or eliminate deficits, or markets for surplus resources. Such an arrangement could also provide that the rate of energy and capacity sold through the pool to meet unanticipated load growth not reflect the availability, or lack of availability, of such energy or capacity. The limitation in this arrangement is that no utility would have the obligation to construct or purchase resources to meet unanticipated load growth, and the arrangement would not insure that there would be resources to meet the region's unanticipated load growth. The consequence would be that the participating utilities having a deficit from unanticipated load growth would share equally in the deficit of the pool.

It is not possible to predict at this time what effect, if any, these alternative actions would have on future resource mix due to numerous other variables. It can be said with some certainty, however, that if BPA did not provide services with the flexible resources of the FCRPS that more resources, both generation and transmission, would be required by the region not only to replace FCRPS resources, but to offset diversity savings lost due to reduced system coordination. Although the effect of providing services is cumulatively significant, from a regional standpoint, the effect of BPA withholding these services from a given utility is not significant. So, for example, if a utility chose not to participate in a conservation program, the withholding of services alone would not be a sufficient incentive to get it to do so. The reason for this is that in the Pacific Northwest, the generating utilities which currently benefit from the provision of BPA services also have some capability to utilize their own resources to shape their own loads and they have certain service rights under the coordination agreement. As BPA rates continue to increase, the economic advantage to a given utility of BPA providing services will continue to decline.

(3) Effects of BPA Providing Services Only to Specific Resource Types.

The question has been asked whether BPA could refuse to provide these services to a particular plant or to a particular type of resource technology, such as conventional nuclear, or coal, or both, and if so, what would be the result.

From a legal point of view, BPA probably could withhold customer services and peaking capacity and nonfirm energy sales from the plant owners if its action were based on determinations of the public interest, but it is doubtful that it could refuse to supply the transmission services. This is in part because of the way the regional grid is planned and constructed and the way it functions, and in part because the Federal Columbia River Transmission System Act provides that the surplus capacity in the BPA transmission grid should be made available to non-Federal entities "on a fair and nondiscriminatory basis." BPA plans and builds expansions in the interconnected regional grid, as distinguished from the radial lines necessary to interconnect a plant to that grid, based on expectations of load growth and the requirements of operational stability and usually well in advance of definite decisions as to the location, technology and size of new powerplants. Thus, at all times there is a significant degree of surplus capacity in the transmission system. In view of this, the statutory language is interpreted as denying the Administrator the authority to deny the plant the appropriate transmission services if the plant is otherwise engineeringly sound, financially feasible and complies with Federal and State environmental laws. From an administrative viewpoint, it would not be practical for the Administrator to adamantly refuse to cooperate with a plant in which the owners had invested considerable sums of money, on which the consumers were relying to supply them reliable electric service, and to which Federal and State siting and licensing agencies and regional planning groups had given their approval.

A policy of this type would serve to isolate future regional power system development from the FCRPS. As previously stated, the region's utilities view the development of thermal generation as a necessity in meeting future load growth. With or without BPA services, these resources will likely be constructed. Under this alternative, utilities would either singly or, more probably, jointly provide the necessary integrating services and facilities, operating independently of the FCRPS in a manner common in other parts of the country.

BPA support of alternatives to the conventional thermal generation would increase the percentage developed but probably not to the point where the utilities constructing resources would forego thermal generation. Therefore, the utilities would continue to develop thermal resources outside the operations of the FCRPS, while utilizing all other resources to the extent they deemed the risks of alternate resource technologies acceptable.

(4) Relation of BPA to WPPSS Nuclear Plants 4 and 5.

The injunction resulting from the court decision in NRDC v. Hodel prohibits BPA from contracting to provide integrating services and facilities to WNP-4/5 until completion and court acceptance of this EIS. A description of these plants is included in Section IV.A.1.a.(2). of this document along with a summary of anticipated environmental impacts. This section addresses the role of BPA services in the decision to complete these plants.

WNP-4/5 represent the only post-Phase 1 generating facilities currently under construction in the region. They were begun at a time when it was assumed BPA would provide services through the FCRPS. BPA is proposing to provide these services, subject to the environmental analysis and public comment procedures required by NEPA, in accordance with its policy to integrate any new resource developed. The services BPA proposes to provide are transmission, load factoring, storage and scheduling, and to the extent necessary, forced outage reserves.

In providing these services and facilities, BPA would utilize existing corridors and resources to the extent possible. Because of the close proximities of WNP-1/3 this is a major consideration as it would markedly reduce both the cost and environmental impacts specifically of transmission development, but also of load factoring resources and forced outage reserves. BPA would utilize the existing hydro system to provide these services. However, additional support resources might be necessary.

If BPA did not provide services, WPPSS would do so. This would most likely be accomplished through contracting and cooperation with other regional utilities, industry, and possibly through arrangements with utilities outside the region. The goal would be to utilize energy exchanges, load diversities, and existing transmission capacity to integrate the plants with limited contruction of new facilities. (Note: Power surplus to the needs of the participating utilities has been sold to the direct-service industries.)

A decision by BPA not to integrate WNP-4/5 with Federal services would not terminate their construction. These plants were planned to accommodate forecasted utility load growth, and while it is possible that conservation and renewable resources will be developed to meet a part of the region's future energy needs, official forecasts support the completion of these plants in the future. In addition, a considerable capital investment has already been made in the plants, making completion economically desirable to the participating utilities.

The major impact of a decision by BPA not to integrate the plants would be increased resource costs and increased rates for participating utilities.

4. Factors that Promote Alternative Generation.

a. External Factors.

There is a great deal of interest in the region and nationally in promoting the development of electric power generation from the use of resources other than through the conventional powerplants using fossil fuels, nuclear energy, or hydro power. The technology, potential, cost and environmental impacts of these alternate forms of generation are described in Section IV.B.2. They include the uses of solar energy, wind, wood, geothermal, and municipal wastes.

A number of factors could stimulate the development of alternative energy resources. Federal, State, utility, and industry programs for research and development, tax incentives, demonstration, or direct financing could result in greatly increased development. Some such programs are already in effect or under consideration. Technical innovations could suddenly alter the costs or applicability of these resources to permit faster or more extensive development. The continually rising costs of conventional fuels, the question of their availability at any price, and their vulnerability to the vagaries of international politics also contribute to the attractiveness of alternative resources.

Public awareness and attitudes are a vital factor in alternative resource development. Greater public awareness encourages applications and the circulation of information improves this awareness. The growing recognition of the value of matching the quality of energy to the quality of its use, which can be efficiently accomplished with alternative resources, also stimultes their application. Environmental sensitivity and local activism are also factors which appear to favor the adoption of alternative resource technologies, as they generally appear to have fewer adverse environmental impacts and thus less controversy involved in their siting and construction.

Collectively, these external factors have a much greater influence on alternative resource development than the options available to BPA to promote such resources.

b. <u>BPA Activities Having Direct Effect</u>.

Under existing law BPA only has authority to construct alternative generation facilities as part of its research and development program. It would be given substantially broadened authority under Alternatives 3 and 4 either to construct production facilities or to support them through long-term contracts to purchase the output.

c. <u>BPA Activities Having Indirect Effect</u>.

BPA's policy to serve any type of resource within the bounds of reliability and environmentally sound operations provides a significant asset in the future development of renewable resources and conservation. By their nature, most renewable resources (excluding combustion systems) are intermittent in availability. One of the major hurdles in making these resources cost-effective is the need for backup systems. Without the services of the Federal Columbia River Power System, the development of large intermittent resources, such as wind-generators, would be inhibited more so than conventional (small hydro) alternate resources. BPA is beginning to investigate the possibility of using the hydro system with its storage capabilities as a "battery" for these systems. In addition, it may be possible to "firm up" some of the region's secondary energy with these resources if the schedules of availability match. Although it is not now possible to predict how much energy will be available from these resources, flexibility of the hydro system to provide integration into the regional power system should provide a definite advantage in reducing their costs to the ratepayer and making such resources economically competitive with more conventional systems. Completion of resource technology assessments currently underway at BPA will help to answer these questions. The existing service policy allows BPA to assist in the integration of any new generation into the system at the lowest possible cost to the region.

Provision of BPA transmission, scheduling, load shaping, and other services provides a significant incentive towards the development of renewable resources. BPA believes that most of the renewable resource potential identified for the Pacific Northwest will be developed as utilities compete for new resources, regardless of what other incentives BPA may be able to offer. However, BPA efforts, including the allocation proposal, would likely result in a more timely and efficient development process.

D. Impacts of the Proposal and Alternatives.

1. Power Generation.

a. Resource Effects.

(1) Existing, Developing, and Committed Resources.

There are external factors unrelated to the proposal or alternatives which could cause cancellation or delay in construction programs. National policy with regard to environmental and safety issues could potentially result in shutdowns of specific types or designs of resources or more stringent operating standards, which could in turn make it technically or economically impossible for a powerplant to operate. Project sponsors could also be forced to abandon or delay construction because of their inability to secure continued sources of funding, particularly when bonds must be approved by voters.

(a) Impacts of the Proposal.

Powerplants presently under construction in the region pursuant to the Hydro-Thermal Power Program would not be affected by the proposal and would be completed as close to schedule as possible. Past experience suggests that delays unrelated to the proposal would be encountered.

Powerplants planned but not yet under construction could be affected by the proposal, although there is a great deal of uncertainty about these effects. The status of each plant in the licensing process may be important. A plant which has undergone siting council hearings may not be subject to re-evaluation prior to initiation of construction programs, although the need for power might change during the licensing process. Moreover, litigation could result in some projects being abandoned. Sponsors adding units to existing projects, such as Colstrip 3 and 4, may have stronger incentives to complete these additional units than a sponsor of a new project might have, because for existing sites, numerous costs are eliminated. The site is established, fuel supply and power transmission are already arranged, and permit procedures have been tested and successfully carried through.

Conservation and end-use resource development efforts in the region could cause changes in the need for new resources, thereby resulting in delays in the need for construction programs or reducing deficits.

(b) Impacts of Alternative 1.

As in the proposal, the major potential for impact on existing resources would result from operational changes.

With fragmented resource planning and uncertainty about new resource developments and BPA power allocations, there would be strong incentives for project sponsors to complete plants under construction or committed. Because BPA would no longer build integrating transmission facilities for non-Federal projects, sponsors might have to assume these costs if arrangements had not previously been made for these services. Limitations of interand intra-regional transmission capacity might limit opportunities for project sponsors to sell power which was temporarily surplus on their systems. Efficiency in the operation of regional resources would be reduced.

(c) Impacts of Alternative 2.

Effects noted for Alternative 1 also apply to Alternative 2. However, with the creation of mutual operating agencies, project sponsors might be better able to finance transmission additions required to integrate plants under construction or committed.

(d) Impacts of Alternative 3.

Under this alternative there would be a high probability that the need for power could be reduced through effective conservation programs. This reduction could delay the need for completion of committed projects or reduce deficits.

Alternative 3 would give BPA authority to acquire cost-effective resources while it would establish a priority for acquisition of conservation and renewable and alternative resources. If cost-effective conservation measures and renewable and alternative resources could be implemented in sufficient quantity and within the same time frame as the target dates for committed large thermal plants, the need for committed plants would also be delayed.

(e) Impacts of Alternative 4.

Alternative 4 probably would result in implementation of strong conservation programs which might delay the need for construction of committed resources. Unless the committed resources were specifically addressed in the legislation necessary for this alternative, the Commission established by the legislation would have to make decisions regarding these resources. Presumably, the Commission would compare the cost, technical feasibility, and lead times of other generation technologies, including alternative and renewable resources, with the costs, commitments, and time which would be required to complete the committed projects.

(2) Future Resources.

Factors in the proposal and alternatives relating to planning, coordination and cooperation, financing, conservation, and transmission services may affect the future types of resources to be developed.

Conservation resources would, in most instances, result in reduced demand for central station energy resources. This would lessen the system's dependence on fossil and nuclear fuels, reduce the likelihood of shortages and curtailment, and lessen the environmental impacts from electrical generation and transmission are discussed in Section IV.B. and in the Role DEIS (1, IV.B.).

Energy resources at the point of end use could result in future lessening of dependence on central generating resources and transmission facilities, and in localized situations, could result in energy self-sufficiency. These systems might be electrical (industrial energy parks, small wind generators, and fuel cells) or nonelectrical systems (passive solar, solar hot water systems, and waste heat utilization), which would provide substitute energy forms to displace electricity. Impacts of end-use energy resources are discussed in Section IV.B.2.a.&b. and in the Role DEIS (1, V.C.).

The environmental and economic impacts of large central station resources are different from the impacts of decentralized small-scale electrical generating plants. Large facilities are generally preferred by the utility industry for their economies of scale. The reader is referred to Section IV.A.1.a. for discussion of the impacts of central station resources in the region and Section IV.B.2. and the Role DEIS (1,V.C.) for their generic impacts. Fewer transmission lines, but of greater capacity, are needed than for small plants. Energy parks or centers represent another type of centralized generation with several large or small plants clustered at one site. Their impacts are covered in the Role DEIS (1,V.D.).

(a) Impacts of the Proposal.

Under the proposal BPA would encourage a higher level of regional conservation and cooperative planning. The Federal high-voltage transmission system would be utilized to integrate new resources, and BPA would continue to offer a range of services. Although BPA would not be able to financially back additional powerplant construction through net-billing arrangements, mutual operating agencies (MOAs) might be able to construct some large central station resources. In addition, the increased degree of regional cooperation and interdependence of utilities achieved under the proposal would tend to make development of alternative resources more likely than at present since arrangements to share the risks of these technologies would be more effective.

As a result of the proposed power planning process, a mixed electrical and nonelectrical regional system would likely develop. Compared to the present system, which consists mainly of large-scale central station electrical generation, there would be somewhat increased conservation and application of end-use, nonelectrical energy resources under the proposal. This would lessen the need for electrical generating resources and therefore reduce the construction and operational impacts of these powerplants. The specific impacts would depend on many factors. However, the overall effects would probably include improved air and water quality and reduced requirements for solid waste disposal, nonrenewable fuel resources, and land for generating plants (Role DEIS: 1, IV-124-127). The mixed system would consist of end-use generating resources, conservation measures, large central station resources, and decentralized small-scale electrical generating plants.

At the same time, the proposal would not alter the authority within which BPA must act, and, therefore, some options now closed to the region would remain closed. Thus, implementation of some conservation programs and/or development of some alternate resources would likely be prevented or delayed.

(b) Impacts of Alternative 1.

BPA would have no responsibility to provide additions to the Federal transmission system under the limitations of this alternative. Utilities, acting individually, would have insufficient financial capability to warrant construction of large central station resources. New resources would probably be small scale and would be constructed closer to load centers. The impacts of these resources such as employment during construction and air pollution and thermal emission during operation, would occur close to load centers and would more directly affect the local population than remote generating stations. These resources would likely to be of conventional types because individual utilities might not wish to undertake the burden of additional costs and risks associated with alternative and renewable plants.

(c) Impacts of Alternative 2.

Under this alternative, MOAs might assume greater responsibility for interregional cooperation and resource planning. Depending on the aggregate financing capability and the rate leverage of such organizations, larger conventional generating plants might be constructed. Some incentive for conservation would exist if financing difficulties for new electric resources were not resolved. A mixed electrical and nonelectrical system would probably result, but there would be more large-scale conventional electric generation than in Alternative 1 and considerably less emphasis on conservation than in the proposal.

(d) Impacts of Alternative 3.

Alternative 3 would give BPA the authority to acquire resource capability and would initiate a formalized regional planning process. This alternative would also specify that feasible and cost-effective conservation, end-use resources, cogeneration, and renewable resources be developed before conventional electrical generating technologies. BPA would then have the authority to acquire the resource capability, including conservation and end-use energy resources, necessary to balance regional energy resources with demands. The result of these priorities and authority would be a mixed electrical and nonelectrical regional electric supply system which would be considerably more dependent on cost-effective conservation than that which would result under the proposal. Greater utilization of renewable resources would also occur. However, it is expected that conventional electrical resources would continue to be constructed as well because cost-effective conservation and renewable resources would not be adequate for all needs. Expanded public participation would be sought in the planning of new projects so there would be a greater level of public acceptability for the types of resources chosen.

(e) Impacts of Alternative 4.

Alternative 4, relative to the other four alternatives, would provide the greatest potential for BPA to construct and acquire cost-effective regional electrical and nonelectrical resources. Under this alternative, mandatory conservation standards could be enforced, voluntary programs could be implemented, and efforts would probably be made to accelerate research and development and application of renewable and end-use resources. To the extent that resources were constructed by a single entity, this alternative could result in maximum energy efficiency and ensure a balance of energy supply and demand for the region, minimizing the impacts of generation on the regional environment, while also avoiding the adverse effects which would result from energy deficits. Electrical energy might be reserved for those uses for which other more appropriate energy forms were unavailable. Other values in addition to economic costs would be taken into consideration, and as a result there might be more emphasis on construction of renewable and end-use resources. This would meet with greater public acceptability on a regional level and therefore would result in more timely action. As in Alternative 3, resource mixes would be determined through regional planning and coordination agreements. Factors other than power benefits would be given added consideration.

b. Effect Of BPA Integrating Services.

(1) Introduction.

During the U.S. District Court's examination of Phase 2 of the Hydro-Thermal Power Program (NRDC v. HODEL), it was concluded that provision of integrating services by BPA (peaking, transmission facilities, wheeling, reserves, load shaping, scheduling, sales of surplus power, and other trust agency arrangements) to utilities developing new thermal resources to serve regional loads promoted the construction of the resource facilities and represented a major component of any regional power program which might be developed. This section identifies BPA's existing policy regarding provision of these services, alternatives to this policy, and provides a discussion of the associated impacts on future regional resource mix. Discussion and definitions of the services themselves are included in Sections IV.A.2.a. (Customer Services), IV.A.3.c. (Transmission), and IV.A.1.a. (Hydro Peaking).

Service Policy. Integrating services are generically defined by the utility industry as those facilities, other resources, and system operational functions, such as load factoring and resource scheduling, which allow a new resource to operate as a part of the regional power system. BPA's existing policy is to provide integrating services to utilities developing any type of energy resource to serve regional loads to the extent BPA has resources and facilities available, and provided the provision of such services does not jeopardize the reliability or reduce the efficiency of the Federal system. In addition, services will be provided only if the Federal system will continue to operate in an environmentally acceptable fashion. It is not administration policy to use the assets of the Federal power system to exclude the development of any resource technology in the region, but rather to utilize its unique flexibility to satisfy future power needs in the most economic and environmentally sound manner.

Both the Bonneville Project Act and the 1974 Transmission Act provide guidance to the direction BPA should pursue with services available from the FCRPS. The Act states: "In order to encourage the widest possible use of all electric energy...the Administrator is authorized and directed to provide...electric transmission lines and substations... for the purpose of interchange of electric energy, to interconnect the Bonneville project with other Federal projects and publicly owned power systems now or hereafter constructed "Section 2(b)1 . . . Section 5(b) goes on to state: "The Administrator is authorized to enter into contracts with public or private power systems for the mutual exchange of unused excess power upon suitable exchange terms for the purpose of economical operation or of providing emergency or breakdown relief."

The Transmission Act refers specifically to transmission services: ". . . the Administrator shall make available to all utilities on a fair and nondiscriminatory basis, any capacity in the Federal transmission system which he determines to be in excess of the capacity required to transmit electric power generated or acquired by the United States."

Operating within these statutory parameters, BPA is not proposing to change its service policy. Due to the large number of uncertainties in the region surrounding future resource development specifically, and power planning in general, the present policy give BPA the level of flexibility desirable to respond to the dynamics of the region's energy system while still taking into account environmental and system limitations.

For purposes of clarity the discussion of the impacts of these services under existing BPA policy is divided into three areas with common implications: hydro peaking, transmission facilities and wheeling; and reserves, load factoring, scheduling, and trust agency agreements.

For purposes of illustration, two alternatives to the existing policy are analyzed. The first would limit BPA's provision of services to those currently under contract; the second would utilize the policy to encourage the development of specific resource technologies while specifically discouraging others.

(2) Services Provided by BPA.

Hydro Peaking. As discussed in Section IV.A.1.a., one of the major thrusts of the HTPP was to accommodate the region's shift from an almost total hydro system to a system relying more and more on utility-owned thermal baseload plants operated in coordination with Federally and non-Federally owned hydro peaking facilities. The development of post-Phase 1 peaking units was intended to provide the capacity needed to supplement the baseload thermal energy. The provision of hydro peaking allows the region's utilities to operate the thermal baselaod plants at a high level of efficiency. This compatibility with other resource types is one of the greatest assets of the regional hydro system.

The environmental impacts of hydro peaking are those associated with increased river fluctuation. These impacts are covered in Section IV.A.1.a. Summarized by order of importance, these include reduced anadromous fish runs, decreased wildlife habitat on islands and riverbanks, conflicts with recreational activities and increased navigational hazards. All of these impacts provide constraints for future development of hydro peaking resources.

Transmission. BPA currently provides the major portion of the regional high-voltage grid used to transfer power from generation facilities throughout the region to load centers where it is distributed to customers. Utilities provide some high voltage main grid lines but mostly the lower voltage transmission for shorter transfers and distribution to ultimate consumers. The coordinated use of a high-voltage grid allows for greater quantities of energy to be transferred with lower line losses and reduced amounts of right-of-way. This translates into fewer acres of land taken out of general use, as well as corresponding reductions in herbicide use for right-of-way management and other impacts of operations and maintenance. A comprehensive discussion of the impacts of transmission lines is included in Section IV.A.3. above and Appendix B of the Draft Role EIS.

Construction of a new resource may not require new regional transmission facilities. BPA builds transmission lines anticipating regional needs and thereby reduces facility duplication (e.g., BPA may build one line to serve several needs). The cost to the region's ratepayers and the environmental impacts are less than if individual utilities each constructed their own separate and therefore more numerous lines. BPA's wheeling services are an extension of its transmission service policy.

Load Factoring, Scheduling, Reserves, and Trust Agency Services. This section covers the contractual and operational services BPA provides which are designed to maximize total system efficiency. Hydro and large baseload thermal resources are planned to operate together so that the thermal resources produce the maximum amount of firm energy per unit of installed capacity, while the hydro system acts essentially as a storage battery to absorb the excess thermal generation during light-load hours and generate additional power during heavy-load hours. This operation of the hydro system is referred to as "load-factoring." Hydro resources also are operated to store excess thermal generation at certain times of the year and to return such generation to the owners of the thermal plants at other times of the year. This operation of the hydro system is referred to as "storage."

Scheduling is the development of an operating timetable for a specific resource which coordinates its energy production with other regional resources in order to meet fluctuating regional demand. Reserves are resources designated to meet contingencies such as forced outages and unanticipated load growth. Trust agency services permit BPA to act as an intermediary for regional entities in the purchase and sale of power. (A more complete discussion is provided in Section IV.A.2.a.)

This portion of BPA's role in the regional power system involves the actual operational integration of hydro and thermal generating resources. BPA and the utilities schedule each resource for maximum system compatibility and efficiency in meeting fluctuating regional loads both on a daily and seasonal basis. This increased efficiency reduces the amount of generation needed to meet loads as well as reducing fuel and other operating costs. Increased environmental impacts from river fluctations arising out of peaking activities are to some extent countered by decreased impacts from more efficient thermal operations.

(3) Impact of Services on Regional Resource Selection.

In addition to generating facilities currently in operation, BPA has expressed willingness, subject to NEPA compliance and system capability, to provide services to utilities sponsoring Phase 1 thermal plants as well as two post-Phase 1 facilities (WPPSS Nuclear Plants 4 and 5). BPA is enjoined, however, from providing services and facilities to the post-Phase 1 plants until completion and court acceptance of this EIS (decisions open to BPA on these specific plants and associated impacts are covered later in this section).

The current regional emphasis on thermal plant development results from a concept common to the utility industry nationwide during the 1960's and early 1970's, in which large coal and nuclear thermal facilities were viewed as the most cost-effective new resource. The emphasis now being placed on conservation and renewable sources of energy was still several years into the future. This shift in emphasis related to resource development is one of the major changes in regional energy planning since the demise of HTPP-2.

The question has been raised: How does BPA's policy for provision of integrating facilities and services impact the regional resource mix? To answer this it is necessary to put services into perspective with other factors affecting the selection of regional resources.

Under the present regional structure, resources are developed by the utilities either individually or in groups. Resource development decisions are based on a large number of criteria including capital costs, total utility costs, existing utility resource mix, availability of services from BPA or other utilities, size and type of load to be served, construction leadtimes, resource reliability, and utility preference. All of these factors must be evaluated and balanced in each decision relating to the choice of specific future resource.

As evidenced by this list, integrating services are only one consideration in choosing a resource technology. BPA's role in this area of coordination primarily serves to reduce resource cost through increased efficiency and a reduced need for both generating and transmission facilities. This in turn decreases the environmental impacts of resource development. In addition, with the exception of the high-voltage grid, BPA is not the sole source of these services. Utility power pools provide portions of the necessary reserves as well as resource scheduling. Some utilities have combustion turbines for peaking and emergency needs and most of the larger utilities have power managers to manage power purchases and sales.

BPA's policy to serve any type of resource within the bounds of reliability and environmentally sound operations provides a significant asset in the future development of renewable resources and conservation. By their nature, most renewable resources (excluding combustion systems) are intermittent in availability. One of the major hurdles in making these resources cost-effective is the need for backup systems. BPA is beginning to investigate the possibility of using the hydro system with its storage capabilities as a "battery" for these systems. In addition, it may be possible to "firm up" some of the region's secondary energy with these resources if the schedules of availability match. Although it is not now possible to predict how much energy will be available from these resources, the flexibility of the hydro system to provide integration into the regional power system should provide a definite advantage in reducing their costs to the ratepayer and making such resources economically competitive with more conventional systems. Completion of resource technology assessments currently underway at BPA will help to answer these questions. The existing service policy allows BPA to assist in the integration of any new generation into the system at the lowest possible cost to the region.

In summary, BPA's service policy does not enable the development of a specific resource type as much as it enhances the development of all resource types to meet regional energy need through increased ability to reconcile individual resource characteristics with the system as a whole, reduced costs, and provision of backup energy for intermittent resources.

(4) Alternative Service Policies.

Effect of BPA Not Providing Services. If BPA did not provide these services, regional resource development would not stop. Regional utilities can and will provide generation as they do in the rest of the nation acting either jointly or individually.

Without BPA, peaking capacity now planned to be provided by Federal hydro facilities would probably be replaced by a combination of inter-utility cooperation in utilizing peak load diversities and existing non-Federal hydro facilities; construction of peaking generation, i.e., combustion turbines or pumped storage; and increased load management. To the extent they were effective, utility cooperation and load management would provide for lesser environmental impacts. [See Section IV.B.1.a.(3). (diversity exchange) and IV.B.2.a.(2). (load management). Environmental impacts of generating systems are covered in Section IV.A.1.a.]

It is not possible to predict precisely how future peaking impacts of the power system would evolve without additional Federal hydro facilities unless it is known specifically what resources would be substituted. It can be anticipated that air quality would be significantly impacted on a localized basis due to increased operation of combustion turbines. Impact shifts from Federal hydro peaking to non-Federal hydro would also be probable. All of these could be mitigated by the implementation of load management programs to reduce the need for peaking power.

In order to market the output of the widely scattered Federal projects, BPA constructed long-distance high voltage transmission lines. As a natural consequence, BPA assumed the regional role of providing the major backbone transmission system which effectively integrated all of the electric generation utilities in the United States portion of the Columbia River Basin. It is highly unlikely that this integration would be terminated under any circumstances due to system reliability and efficiency benefits. If BPA did not continue to fill this role, the utilities would. The outcome of this shift would be twofold. First, without additions to the FCRPS, future transmission needs would be met with more limited purpose lower voltage lines constructed with higher associated impacts and increased costs. Second, plants would potentially be sited closer to load centers to reduce transmission costs. Depending on the circumstances, this may or may not affect the resource technology chosen for construction.

Sales of surplus power, scheduling, and other regional activities in which BPA is a participant would also continue, undoubtedly with some loss of efficiency. However, in the areas of load factoring and load growth reserves BPA has a more significant role.

For load factoring, one alternative would be an agreement among utilities owning capability of a number of thermal plants. The group would coordinate its own loads and resources prior to contracting for a single load factoring service from BPA. Thus, customers could take full advantage of the capabilities of their own generation and reduce the load factoring service needed from BPA. (This form of thermal coordination agreement, providing for coordinated scheduling among utilities of thermal plant output, is discussed in detail in Appendix A of the Draft Role EIS).

Another alternative to BPA providing load factoring service would be for utilities that own thermal plant capability to enter into bilateral arrangements for service with utilities that have hydro generation and available reservoir storage. This alternative is limited by the number of utilities that have the capability to provide load factoring service, and by the fact that it excludes BPA, which through operation of the Federal Columbia River Power System, has one-half of the region's hydroelectric capability and a major part of the storage.

If BPA were not to provide a load factoring service, one of the capabilities of the Federal hydro system would be wasted. The customers would have to provide their own load factoring service requirements by (1) varying their own baseload generation, with consequent loss of firm load-carrying capability, when constant output may be more desirable from cost, equipment maintenance, and environmental impact standpoints; and (2) constructing or purchasing power from additional pumped storage, or peaking or intermediate load thermal plants.

If BPA did not provide load growth reserves to meet the utilities' unanticipated load growth, the utilities would have three basic alternatives. The first alternative would be to secure firm resources annually from other utilities in amounts sufficient to meet energy or capacity deficits resulting from unanticipated load growth. The ability to purchase sufficient amounts to cover deficits would be dependent upon the availability from other generating utilities of energy or capacity which had been determined in advance of the operating year to be surplus. The amount of energy and capacity available in advance of the operating year may affect the rate utilities would pay for this capacity and energy. If firm capacity and energy to meet forecasted deficits were unavailable in advance of an operating year, due to unanticipated load growth, some utilities, unable to acquire firm resources to eliminate their deficit, might start the operating year with a forecasted deficit. If nonfirm energy or surplus capacity became available during the year, such utilities would then be able to meet their firm loads with nonfirm energy or surplus capacity. If nonfirm energy or surplus capacity did not become available during the operating year, utilities with deficits would have insufficient resources to meet their firm energy or capacity requirements.

Regional utilities have the second alternative of constructing generating facilities, or purchasing generating project output under long-term arrangements in amounts which would provide sufficient resources above their forecasted loads to provide a margin for unanticipated load growth. Utilities electing this option would have sufficient resources to avoid deficits resulting from unanticipated load growth. To the extent that such resources are estimated in advance of the operating year to be surplus to the utilities' requirements, the owner utility could sell surpluses to utilities having a load-resource deficit. If such surplus resources could not be sold in advance of an operating year, the utility would attempt to dispose of the output from these resources as surplus energy or capacity during the operating year, perhaps at a rate insufficient to recover the cost of generation. If the cost of such resources could not be recovered, the cost of such resources would be absorbed by the owner utility, to the extent that cost could not be mitigated by reduced operation.

If BPA does not make load growth reserve energy and capacity available, the third option available to a utility in need of load growth reserves would be to enter into an arrangement with other utilities to pool their resource surpluses and deficits in advance of an operating year, balancing surpluses and deficits of participating utilities, and thereby attempting to reduce each participating utility's projected surplus or deficit of resources. This arrangement would have the advantage of providing each participating entity with an equal opportunity to secure resources to reduce or eliminate deficits, or markets for surplus resources. Such an arrangement could also provide that the rate of energy and capacity sold through the pool to meet unanticipated load growth not reflect the availability, or lack of availability, of such energy or capacity. The limitation in this arrangement is that no utility would have the obligation to construct or purchase resources to meet unanticipated load growth, and the arrangement would not insure that there would be resources to meet the region's unanticipated load growth. The consequence would be that the participating utilities having a deficit from unanticipated load growth would share equally in the deficit of the pool.

It is not possible to predict at this time what effect, if any, these alternative actions would have on future resource mix due to numerous other variables. It can be said with some certainty, however, that if BPA did not provide services with the flexible resources of the FCRPS that more resources, both generation and transmission, would be required by the region not only to replace FCRPS resources, but to offset diversity savings lost due to reduced system coordination.

Effect of BPA Providing Services Only to Specific Resource Types. The impacts of BPA's second alternative calling for the use of BPA services to promote or discourage specific types of technology are best illustrated by examining a policy in which BPA makes services available only to renewable resources and conservation and excludes conventional thermal generation.

In summary, a policy of this type would serve to isolate future regional power system development from the FCRPS. As previously stated, the region's utilities view the development of thermal generation as a necessity in meeting future load growth. With or without BPA services, these resources will likely be constructed. Under this alternative, utilities would either singly or, more probably, jointly provide the necessary integrating services and facilities, operating independently of the FCRPS in a manner common in other parts of the country.

BPA's endorsement of renewable resources and conservation would promote their development through: (1) a reduction in costs if a hydro system backup proved compatible; and (2) reduced development risks if Federal power reserves were available to meet unanticipated demand resulting from ineffective programs. No matter what BPA does, a certain percentage of these resources will be utilized because of costs, leadtimes, and the need to meet near-term deficits. Federal support would increase the percentage developed but probably not to the point where the utilities constructing resources would forego thermal generation. Therefore the utilities would continue to develop thermal resources outside the operations of the FCRPS, while utilizing all other resources to the extent they deemed the risks of alternate resource technologies acceptable.

(5) WPPSS Nuclear Plants 4 and 5.

The injunction resulting from the court decision in NRDC v. Hodel prohibits BPA from contracting to provide integrating services and facilities to WNP-4/5 until completion and court acceptance of this EIS. A description of these plants is included in Section IV.A.1.a.(2). of this document along with a summary of anticipated environmental impacts. This section addresses the role of BPA services in the decision to complete these plants.

WNP-4/5 represent the only post-Phase 1 generating facilities currently under construction in the region. They were begun at a time when it was assumed BPA would provide services through the FCRPS. BPA is proposing to provide these services consistent with NEPA and administration policy to integrate any new resource developed. The services BPA proposes to provide are transmission, load factoring, storage and scheduling, and to the extent necessary, forced outage reserves.

In providing these services and facilities, BPA would utilize existing corridors and resources to the extent possible.

Because of the close proximities of WNP-1/3 this is a major consideration as it would markedly reduce both the cost and environmental impacts specifically of transmission development, but also of load factoring resources and forced outage reserves. BPA would utilize the existing hydro system to provide these services. However, additional support resources might be necessary.

If BPA did not provide services, WPPSS would do so. This would most likely be accomplished through contracting and cooperation with other regional utilities, industry, and possibly through arrangements with utilities outside the region. The goal would be to utilize energy exchanges, load diversities, and existing transmission capacity to integrate the plants with limited construction of new facilities. (Note: Power surplus to the needs of the participating utilities has been sold to the direct service industries.)

A decision by BPA not to integrate WNP-4/5 with Federal services would not terminate their construction. These plants were planned to accommodate forecasted utility load growth, and while it is possible that conservation and renewable resources will be developed to meet a part of the region's future energy needs, official forecasts support the completion of these plants in the future. In addition, a considerable capital investment has already been made in the plants, making completion economically desirable to the participating utilities.

The major impact of a decision by BPA not to integrate the plants would be increased resource costs and increased rates for participating utilities.

c. Load Effects.

Load effects are those actions indicated in the proposal and alternatives which might directly alter the magnitude or shape of regional electric loads and thereby produce changes in system operations. The potential for such changes under the proposal and alternatives would vary principally with the prospects for implementing conservation, peakload management, development of end-use energy resources, and service to BPA's DSI customers.

(1) Conservation.

The direct effects of implementing conservation measures under the proposal and alternatives are described in Section IV.B.1.b. Their effects on system operations are discussed here. Conservation would affect system operations in two closely related ways.

First, conservation would reduce overall electric energy requirements and therefore reduce the rate at which new energy resources would need to be integrated into the hydro system.

Thus, in addition to slowing the accumulation over time of the generation impacts of new energy resources (Section IV.B.1 above and Role DEIS: 1, V-224-320) there would result a similar reduction in the need to shape or back up the output of these new resources.

Second, assuming that more opportunities exist for conserving daytime than nighttime consumption of electricity, conservation would tend to increase the regional load factor, thereby reducing system peaking requirements relative to energy loads. This would tend to slow the rate at which new peaking resources would have to be added. This means that the impacts of fluctuating the river for peaking would not increase as rapidly in the future (Section IV.A.1.a. above and Role DEIS: A, III-1-188). Reduction in the need for alternative load following resources, such as pumped storage or combustion turbines, would result in other environmental consequences. Pumped storage reduction would mean higher night-time flows within the hydro system, to the possible benefit of downstream fish migrations. Reduced need for combustion turbines would essentially mean reduced atmospheric emissions during peak load periods.

(2) Peakload Management.

Depending on the goals of the program and the techniques employed, peakload management could reduce peak loads either by shifting some loads from peak intervals to off peak hours, or by simply distributing peak loads over a longer peak period with little or no effect on minimum loads. The former would have the greater beneficial effect on the regional load factor.

In addition to delaying the need for additional hydro or other peaking resources (see Section IV.D.1.a.(1)), these load-shape modifications would affect hydro operations by altering the daily pattern of water releases. Load shifts from peak to off-peak would produce the most dramatic reduction in the environmental impacts of hydro peaking because, in addition to reducing peak load generation, off-peak generation would increase, resulting in a compound reduction of river fluctuations. Current estimates indicate that transference of 3,000 MW of daytime loads to nighttime hours could reduce by half the water surface (reservoir forebay and tailwater) fluctuations and resulting environmental impacts at hydro peaking projects throughout the region (Section IV.A.1.a. and Role DEIS: A, III-1-188). Reduction or delay in the need for thermal peaking resources would result in reduced emissions from operation of those units.

The second type of peak load management, that which reduces and flattens the peak load curve, would produce two resource effects: a delay in the need for new peaking resources and an increase in the need for intermediate load following resources (see Section IV.D.1.a.(1)). River fluctuations, and therefore the environmental impacts of peaking, would not be reduced as much as in the preceding case, even though the magnitude of peak loads might be decreased by the same amount. The difference results from the fact that the displaced loads would not be carried in off-peak hours, thus would not have the additional effect of increasing minimum flows. Moreover, lengthening the peak interval, which requires the addition of intermediate load-following resources (probably thermal), would yield a different set of impacts associated with the operation of these resources during an extended peak interval.

Some techniques for peakload management, such as time-of-day pricing or mandatory load shedding, would have adverse socioeconomic impacts on some sectors of the population, due to higher costs, changes in daily or weekly schedules, or economic losses due to curtailment.

(3) End-Use Energy Resources.

These resources could displace some regional electric generation, reducing regional electric energy loads (see Section IV.D.1.a.(1)). Given the wide range of technologies which might be introduced, it is difficult to predict how resources would alter load shape or the regional load factor, thus it is equally difficult to anticipate how they might alter system operations. The main effect of end-use resources would be to reduce the need to develop new generating resources (thus reducing the impacts of generation on air, water, and land resources), although load-following resources might be needed instead.

Because many of these resources could produce energy only intermittently, they would require backup capacity from the regional generation system. If the number of individual units was large (and depending in some cases on their regional distribution, e.g., wind and solar systems), and if part of their total output was sufficiently dependable to be considered firm power, less than 100 percent backup capacity would be needed. This scenario, however, represents an advanced stage in the development of end-use energy resources, and in all probability is only achievable beyond the time frame of this EIS. Thus, in the near term, there would likely be little or no operational effect on the hydro system of a program to develop such resources. End-use resource development would allow displacement of less environmentally desirable thermal baseload energy generation but would require the addition of backup capacity resources (see Section IV.D.1.a.(1)).

(4) DSI Loads.

Under the proposal and alternatives, three possibilities exist with respect to the role of DSI loads in the region's electric energy system: (1) they could continue as direct-service loads in the region; (2) they could become firm or interruptible loads of the region's retail utilities; or (3) they could become unavailable to the region as markets for power (see Sections IV.D.1.a.(1) and IV.D.2.e.). The significant variables regarding the effect of DSI options on system operations are the availability of DSI reserves provided through interruptibility of their loads and operational considerations due to the higher system load factor resulting from DSI service.

The first option, continuing direct service, represents continuation of existing practice, therefore it would not alter impacts associated with system operations.

Under the second action, if DSI reserves were not available to the region, and the region needed to replace them, greater demands would be placed on the hydro system or other resources to provide backup, or the likelihood of outages would be increased until other reserve capacity could be developed (see Section IV.D.1.a.(1)). This situation could result if the DSIs left the region, if they developed their own independent power resources, or if they were served by retail utilities on an "all firm power" basis without provision for interruptibility.

Lesser degrees of the availability of DSI reserves could result from various possible developments. Retail service could provide for interruptible reserves, but priority in the use of those reserves could be retained by the utility serving the industrial load, thus for the region as a whole the DSI reserve would be less accessible. It is also possible that some DSIs would obtain retail service while others would not. An independent power supply for DSIs could also provide system reserves which, depending on contractual terms, could partially or fully replace existing DSI reserves. On the other hand, if utilities provided backup to self-generation by DSIs, regional reserve requirements would increase. To the extent DSI reserves were less accessible than at present, additional reserves would be required, possibly in the form of greater operational demands on the hydro system.

In the third possibility, if DSIs were not served by the regional power system, either because they ceased operations in the region or because they developed independent power supplies, the result would be that current deficit projections would be reduced. Present DSI power would be provided to other regional loads. The water used to serve nighttime DSI loads might have to be spilled or sold as secondary or surplus energy in order to provide the minimum flows necessary for fisheries or other nonpower uses of the river. If not, the river flow would fluctuate more widely due to the reduced nighttime load.

DSI plant closure would result in some short-term environmental benefits because impacts of plant operations would cease. Adverse socioeconomic effects would also occur, such as losses of employment and tax revenues.

In the event of short-term load-resource imbalances, termination of DSI service could also require implementation of alternative operating strategies. If DSIs were to remain in the region and build their own generating resources, but agreed to provide some reserves for the region, these operational (as well as resource) effects and their associated environmental and socioeconomic impacts could be lessened. However, the exact nature of the effects, with or without the reserve commitment, is difficult to predict at this point without further specification of the changes and detailed studies of the consequences.

The load changes, principally load reduction potentials, discussed in this subsection also could have some indirect consequences for system operations by way of their aggregate effect on the regional power system. To the extent that conservation, load management, end-use energy resources, and possible DSI service changes contribute to reducing the prospects for load-resource imbalances, that outcome has implications for development and utilization of the regional transmission grid, acquisition and sale of power outside the region, and regional attitudes toward no power aspects of river management, each of which could ultimately affect system operations. The specific effects of these relationships are discussed under the appropriate subsections which follow dealing with transmission, interregional transactions, and nonpower considerations.

(5) Comparison of the Proposal and Alternatives.

(a) Impacts of the Proposal.

The proposal provides no new authority for BPA or mechanisms for the region to acquire new resources (including conservation), manage its loads, or ensure a supply of power to existing DSI customers. This places substantial limits on the capabilities and incentives for BPA and the region's utilities to significantly modify prevailing resource development trends, and creates considerable uncertainty as to the future role of the DSIs in the regional power system.

The proposal does stipulate a more vigorous effort on the part of BPA in encouraging conservation in the Pacific Northwest. Neither the proposal nor any of the alternatives specifically addresses peakload management; however, greater system efficiency resulting from peakload management would fit within BPA's definition of conservation, and BPA currently has the authority to institute wholesale peakload pricing. However, the effect of wholesale rates on ultimate consumption depends on the degree to which retail rates reflect wholesale rate structures. Both conservation and peakload management could reduce the need for additional resources, but the extent or effect of these programs is difficult to predict.

Under the proposal, BPA would encourage the development of cost-effective and feasible renewable, unconventional and conventional resources. To the extent that these included end-use resources, system generation requirements could be reduced. Thus, impacts of generation on air, water, land use, employment, and so on also could be reduced, although demands on the hydro system might increase. However, utilities developing resources would continue to select resources based on their own needs and criteria; BPA's role would be advisory only.

In the proposal, the focal point for regional cooperation and coordination is a regional planning document. To the extent this document and the underlying planning process (including greater public involvement) provided a genuine basis for joint rather than fragmented regional action, there would exist a realistic basis for implementing conservation, peakload management, and end-use resource programs on a regional scale. Cooperation and coordination could also work against development of these resources, though, because increased efficiency could reduce the need for all resource types, including these measures. Public input could lead to decisions opposing unpopular measures, such as peakload pricing.

Under the proposal, BPA would continue to offer services to integrate new and existing regional generating resources with the Federal hydro system, thereby providing a positive stimulus for the development of resources. To the extent that this would encourage continuation of current development trends at the expense of conservation, peakload management, and end-use energy resources, minimal load reductions from these sources would be likely.

The net effect of these characteristics of the proposal leads to the conclusion that only minor load reduction or load shape modifications are likely due to conservation, load management, and end-use resource installations.

The proposal would be unlikely to produce substantial investment in conservation, load management, end-use resources, and unconventional central station generation. Whereas regional energy policy and institutional capabilities would favor such investments, the need to do so would be less than under Alternatives 1 and 2. From an operational standpoint, this would mean extension of the existing hydro-thermal relationships.

By contrast, there is a rather high probability that uncertainty surrounding DSI service could lead either to substantial load shifts, if the DSIs were successful in obtaining utility-type service, or load reductions, if they constructed or acquired their own resource capability or ceased Pacific Northwest operations. Because of increased regional planning and coordination, the reserves currently provided by the DSIs might be partially retained under a reciprocal service arrangement if the industries continue operations in the region.

In terms of the uncertainty of DSI service, the proposal is like the first two alternatives, with the possible exception of the reserve provisions, whereas Alternatives 3 and 4 both provide for continued DSI service. It is likely, therefore, that under the proposal, system operations could be significantly modified by loss of DSI loads. The extent to which these changes might be different than under Alternatives 1 and 2 would depend on whether BPA and the region's utilities could and would want to preserve some of the DSI reserve coverage. Because of the uncertainty surrounding DSI service, the impact of the proposal on DSIs cannot be predicted.

(b) Impacts of Alternative 1.

This alternative does not provide authority for BPA to acquire output of new resources. Thus the development of new resources would not be directly aided by BPA, thereby limiting the region's ability to implement conservation and peakload management, develop end-use resources, and continue DSI service. Although the need might be greater than under the proposal, and utilities might undertake such developments independently, the chances of success would be reduced.

Even without actual BPA acquisition of new resource output, there would be some encouragement of conservation, peakload management, and end-use resources, but there would not be the deliberate incentive and support of a BPA information program and regional planning processes as under the proposal. At least some of the stimulus for pursuing these programs would derive from the necessity to find alternatives to large-scale thermal generation. The most likely scenario, however, would be construction of smaller-scale conventional resources.

The lack of coordination under this alternative would reduce the prospects for the above resource alternatives, and would also reduce the chances of continued DSI service. If resources could be developed, costs (hence also power rates) would likely be higher than similar developments under the proposal.

The diminished role of BPA in providing services to new resources would further reduce the probability of conservation, peakload management, or end-use resource development as well as reducing the likelihood of DSI service.

The overall effect of this alternative would be to provide little aid in the development of conservation, peakload management, or end-use resources, but it would result in a greater demand for such resources, which if developed would be somewhat more costly than with greater regional coordination. Continued service to DSIs would be unlikely, and operational effects would follow accordingly.

(c) Impacts of Alternative 2.

Because of its similarity to Alternative 1 in terms of the absence of BPA acquisition authority and the lack of an information program and planning process, the effects of this alternative are closely akin to those of Alternative 1. Two differences are apparent: this alternative includes the formation of MOAs, and it provides a larger BPA role in providing services to integrate resources into the regional system.

The effects of these differences would be to enhance the development of conventional resources, thus reducing the pressure on utilities to invest in conservation, peakload management, and end-use resources, and increasing the chances for continuation of DSI service. The formation of MOAs would also improve decisionmaking and reduce the costs of conservation, peakload management, and end-use and conventional resource development programs which might be undertaken. However, such programs would, on the whole, be unlikely to occur. Thus, as in Alternative 1, regional power operations would be relatively unlikely to change in response to unconventional resources, but they might have to adapt to the termination of DSI service.

(d) Impacts of Alternative 3.

By its provision of BPA purchase authority, this alternative would greatly enhance conservation and renewable resource investments, and permit development of conventional resources, thus virtually assuring continued DSI service. The priority this alternative gives to conservation and renewable resources also enhances the probability of developing these types of resources. The planning and information procedures also contribute to the impetus for conservation, peakload management, and end-use resource development.

Compared to Alternatives 1 and 2, this alternative would have different operational effects. Whereas conservation, peakload management, end-use and unconventional small-scale resources would be unlikely under those alternatives, they would be likely to develop under this alternative, resulting in the the necessary load-following adjustments. Whereas DSI termination would be possible under Alternatives 1 and 2, and the operational effects of termination would have to be considered, continued service is virtually certain under this alternative, thus no operational changes from present DSI service would be anticipated.

Environmental effects of these measures would be generally positive, due to the lesser impact of conservation, peakload management, and end-use resources, as compared to conventional power resources. They would also contribute to the conservation of nonrenewable fuels.

(e) Impacts of Alternative 4.

There is little difference between Alternatives 3 and 4 with respect to operational effects. Alternative 4 provides a somewhat stronger role for BPA and the regional energy commission in assuring balance between supply and demand. The effect of this stronger role on operations would be to marginally increase the ease with which resources, conventional or otherwise, would be developed. As with Alternative 3, retention of DSI service would not introduce any significant operational adjustment. Backup requirements and other operational effects of conservation, peakload management, and end-use resources would substantially increase the probability of operational changes in the regional power system.

d. Interregional Transaction Effects.

Interregional transactions are defined as power acquisitions, sales, exchanges, and arrangements that result in power flows between adjacent regions or systems over high-voltage transmission interties. Contractual arrangements dictate the terms and conditions under which these take place. The basis for transactions is the existence of diversities between systems (Role DEIS: A, IV.A.1., IV-8 to IV-21). Some, such as hourly peakload and seasonal load diversities and streamflow diversities, are peculiar to the systems concerned; others, such as forced outage reserve pooling, simply reflect the value of increasing scale to cushion the effects of random events. Disparities in resource development are another example of potential diversity between regions (Role DEIS: C, IV.D., IV-82 to IV-117). One region may be deficient and another have surplus generation at any given time. To the extent load-resource imbalances in two or more regions complement each other, opportunities exist for interregional transactions. Optimum utilization of the potential for importing and exporting electricity depends on the physical and institutional capabilities of the system. This requires an adequate regional transmission system, sufficient intertie capacity, and considerable coordination of generation, transmission and marketing functions. The environmental and socioeconomic effects of this region's secondary energy sales on the Pacific Northwest and California are discussed in the Role DEIS (C, IV). The impacts resulting from changes in interregional coordination are covered in the Role DEIS (A, IV). For up-to-date surplus secondary information refer to current West Group Forecast Table V, published by Pacific Northwest Utilities Conference Committee.

In evaluating the influence of the proposal and alternatives on interregional transactions, it is necessary to consider both ability and need for regional imports and exports of power. The potential effects of differences in interregional transactions on system operations under the proposal and alternatives are assumed to derive from variations in both the ability and need for such transactions. To a large degree, ability and need are inversely related. The greater the level of regional coordination, the better able the region would be to acquire and sell power, but also the more likely that loads and resources would be in balance, reducing the need to import or export. Conversely, with limited coordination, the region might be more in need of acquiring or disposing of power to offset resource imbalances, yet less able to do so.

For purposes of discussion, the effects on system operations are divided into two categories: those deriving from the need to import power and those deriving from the need to export power. Exchanges involve two-way power flows, and therefore transcend the two transaction categories. The emphasis in each case is on those circumstances deriving from resource deficits and resource surpluses, respectively. Within the two separate discussions, analysis is further divided on the basis of the region's ability to import or export power. The operational effects are fundamentally different depending on whether interregional transactions or some other strategy is required, or diversity benefits simply lost. Import and export effects vary depending on the type of transaction (sale or acquisition, exchange, storage, etc.), which in turn depends on the type of power involved (peak or energy). Where possible, operational changes are further differentiated into seasonal and daily effects.

(1) Import Effects.

Under the proposal and alternatives, regional deficits in energy or capacity could occur, creating a need to import power. The region's ability to acquire such power or take advantage of other interregional diversities could also differ among the five alternatives.

(a) Energy Imports.

Regional deficits in energy could result from low water, failure to develop sufficient resources, or unanticipated load growth. If the Pacific Northwest was energy deficient and able to acquire energy from another region, operation of existing baseload generation probably would be no different on a seasonal or daily basis than the baseline case in which loads and resources are in balance, depending on the type of power available and conditions on its delivery. If the energy deficit was large and the region was able to offset a substantial portion with imports, existing load-shaping resources might be inadequate to shape these imports to baseload, especially if low water conditions were the cause of the deficit. In the short run, this might necessitate supplemental conservation or load curtailment. If the deficit was expected to persist, additional intermediate load-shaping resources might have to be built, with accompanying impacts on the environment.

If energy or peak-energy exchanges were involved, hydro operations would be altered, depending on both the type and terms of the exchange. The latter would determine whether the effects were seasonal or daily. If deliveries were needed and available from a variety of sources on an intermittent basis throughout the year, this would have the effect of imposing an essentially random regulation on the existing hydro cycle. To the extent backup drafting coincided with peakload drafting, the adverse impacts of peaking would be accentuated; if not, the impacts would be tempered. If energy deliveries were regularly available on a nighttime basis only, the probable effect on system operations would be to reduce nighttime hydro generation, thereby accentuating river fluctuations and possibly reducing daily minimum flows or requiring spillage. Operation of thermal load-shaping resources would probably add to the levels of atmospheric emissions during those periods when energy imports were unavailable.

(b) Capacity Imports.

Regional deficits in capacity would most likely result from cold weather, low water conditions, imposition of constraints on hydro system operations, plant delays, or unanticipated load growth. If the region were deficient in capacity and able to make up the deficit with capacity imports, the primary operational effects would be on the hydro system. Their distribution and magnitude would depend on when and in what amounts capacity was delivered, and whether it was made available on a purchase or exchange basis. If all or a portion of the capacity imports were contracted on an exchange basis, adjustments in hydro regulation would vary depending on the type of exchange and the amounts and time of return deliveries. For example, to the extent seasonal peakload diversity existed between two regions, the effect of diversity-capacity exchanges on this region's hydro operations would be to increase summertime peaking, a period when their impacts on other river uses are especially pronounced. If peak-energy exchanges were executed (importing capacity and exporting energy), the most likely effect would be to increase off-peak generation, thereby reducing river fluctuations, irrespective of the season. If critical water conditions produced the capacity deficits, capacity exchanges might not be feasible.

(c) Energy and Capacity Import Limitations.

In the event the region was unable to fully offset energy or capacity deficits through interregional transactions, alternative responses would be required and would impose a different set of operational consequences and impacts. The only effect of an energy deficit on baseload resources would be to further concentrate refueling and maintenance scheduling and other planned outages in the summer months in order to maximize availability during the heavy load months. This could increase the probability of forced outages, requiring additional load curtailments. The additional displacement of thermal generation by hydro energy in summer months would tend to reduce river fluctuations, but could jeopardize energy capability in the winter months, thereby increasing the chances that mandatory conservation or curtailment might be necessary.

The effects on system operations of a peak deficit, without the capability to import sufficient power to meet loads, would be limited primarily to the hydro system, or any other installed load-shaping resources, because of the limited load-following capabilities of baseload thermal generation. Seasonal hydro operations would probably remain unchanged, but changes in daily and weekly hydro regulation would be dependent on the extent to which load reductions and shifts were achieved through conservation, peakload management, or curtailment. See Subsection IV.D.1.a. for discussion of the load changes, operational effects, and impacts these actions could produce.

Inability to import capacity could force operation of the region's marginal load-following resources, adding to the cost of power and increasing regional atmospheric emissions in peakload hours.

(2) Export Effects.

Under the proposal and alternatives, regional surpluses in energy or capacity could result from overbuilding generation resources. The region's ability to market its surpluses or take advantage of other interregional diversities could also vary among the alternatives.

Under conditions of excess generating capacity, the Pacific Northwest generation system might be operated in excess of regional loads to provide power to loads outside the region. Because loads grow more or less continuously, whereas generating resources are built incrementally, the region might consciously schedule its resource developments in order to market the surplus output of some powerplants in the interim before the full output was needed in the Pacific Northwest. If the two interconnected regions experienced reciprocal shortages and surpluses in peak and energy resources, two-way (exchange) transactions might be arranged, as discussed above under import effects.

Surpluses in energy or capacity in one region might be purchased by another region because it either had insufficient resources to meet its own loads or chose to displace some existing generation for economic or environmental reasons. The net effect on Pacific Northwest system operations would be the same in either case, depending on the amount, shape, and timing of the deliveries. In the receiving region, the net effect would be fewer impacts, but their type and distribution could differ in the two cases. Exports to offset resource deficits in other regions would reduce or avoid the need to implement conservation, load management, or load curtailment measures in those regions. Resource displacement would reduce power costs and reduce the adverse environmental impacts of generation.

(a) Energy Exports.

If the region constructed too many energy resources and the excess output was marketable outside the Pacific Northwest, the effect on operations would be to increase annual plant capacity factor and operational efficiency generally, and to decrease the probability of plant shutdowns or reduced output levels due to excess capacity construction. Because this would be surplus generation, it would place no additional backup burden on the hydro system.

If high water conditions were the cause of regional energy surpluses, Federal secondary hydro energy likely would be purchased by Pacific Northwest utilities, under provisions of regional preference, to serve customer loads in order to generate power for sale outside the region. If excess hydro exceeded the region's capability to export or surpassed available surplus markets, the region's utilities might choose to displace some thermal generation with hydro in meeting their firm loads, reducing total thermal output and impacts.

In terms of interregional transactions, the effects of high water years on hydro operations could be substantial. A continuous delivery of surplus water was scheduled, daily reservoir and tailwater fluctuations would not change, but average daily flows would increase, potentially benefitting nonpower uses dependent on minimum flows. If hydro generation were purchased to serve regional utility loads, there would also be a potential effect on system operations by reducing thermal backup requirements on the hydro system.

(b) Capacity Exports.

Given sufficient water, generation, transmission and marketing capability, and the existence of an export market, increased peakload generation in the Pacific Northwest could occur if exported generation were scheduled during Pacific Northwest peak intervals, producing the adverse environmental consequences of increased water fluctuations.

If this power was made available either on a peak-energy or diversity capacity exchange basis, additional operational adjustments could occur in response to the energy or capacity return deliveries to the Pacific Northwest. Deliveries of capacity to other regions during the spring and summer months, with return in the winter months, would increase average daily flows and fluctuations in spring and summer and reduce them in winter. Peak-energy exchanges would have the same seasonal effect on average daily flows and spring-summer fluctuations. The magnitude of winter fluctuations would not change, but the tailwater and reservoir forebay elevations would be reduced. Spring and summer increases in daily flow would be beneficial to fisheries and recreation, whereas winter decreases would not significantly impact either use. Increased fluctuations in any season would be generally detrimental, whereas reductions would be beneficial to other water uses. In a high water year, with system capacity installations sufficient to meet winter firm peak loads, similar adjustments to hydro operations could occur, except that the magnitude of additional peaking for export in the summer months would be limited by the difference between summer and winter peak loads.

(c) Energy and Capacity Export Limitations.

1. Surplus Energy.

In the event the region had surplus energy, but was limited in its capability to export such power, the potential operational effects would vary depending on water conditions and the extent to which the region had overbuilt baseload generation.

If high water conditions alone were the cause of regional energy surpluses, the effect on thermal generation could be to displace it with hydro. Economic criteria would dictate that more expensive thermal be displaced by cheaper hydro anytime the cost of purchasing hydro is less than the variable costs of thermal generation. The effects on hydro operations would be essentially the same as the earlier case in which hydro freed up thermal to generate for export that is, higher daily flows and reduced backup requirements. In the present case, however, the region would be unable to market the surplus, resulting in Pacific Northwest thermal shutdowns, and the running of oil-fired generation in the Pacific Southwest. Aside from the changes in hydro operations already described, one effect of displacement would be to reduce the environmental impacts associated with thermal operations. Increased hydro energy generation probably would not reduce daily fluctuations, but would increase average daily flows, and most importantly, off-peak minimum flows.

If energy surpluses could not be marketed, the only likely recourse would be to idle the most expensive and environmentally harmful plants in the region. Optimization of this effort would depend on the degree of regional coordination and level of interconnection of generating resources and load centers. The objective would simply be to minimize the impacts by shutting down the least efficient resources. This situation could be either compounded or offset depending on concurrent streamflow conditions.

2. Surplus Capacity.

In the event: (1) the region overbuilt hydro peaking resources relative to firm peak loads, (2) high water conditions permitted generation of surplus capacity in the spring and summer months, and (3) the region was not capable of exporting its surplus output, the operational effects on the hydro system would be very different than with exports. If limited export capability precluded utilization of the excess generating capacity, potential additional water level fluctuations would be reduced, but average daily drafting for power would also be reduced. If it became necessary to release additional water to accomodate nonpower requirements, this water would have to be spilled.

(3) Comparison of the Proposal and Alternatives.

(a) The Proposal.

Among the five alternatives, the proposal occupies an intermediate position in terms of both need and ability to engage in interregional transactions. The existence of mutual operating agencies, an active BPA role in planning, and the preparation of a power planning document would tend to improve the region's chances of resource sufficiency and reduce the need to seek interregional sources or outlets for power, while also rendering it more capable of doing so than under Alternatives 1 and 2. The proposal is inferior to Alternatives 3 and 4 in these respects, because the trends described above would simply be accentuated under both. Relative to current regional conditions, the proposal represents a marginal improvement in terms of coordination and capability to plan and finance new generation. Consequently, the pressures or incentives to increase the level of interregional transactions likely would not change substantially from the present, with a corresponding negligible effect on system operations.

(b) Alternative 1.

Alternative 1 occupies the low end of the spectrum on the scale of coordination and probability of load-resource balance. As such, it represents the situation in which the region would be most likely to need to take advantage of interregional transaction opportunities, but least able to fulfill that need. Given the financing difficulties regional utilities would face in attempting to develop additional large, baseload thermal resources, it is more likely that the region would experience resource deficits than surpluses under Alternative 1. Consequently, the operational effects are likely to be those described in the preceding generic section under energy deficits without the option of acquiring power from outside the Pacific Northwest.

(c) Alternative 2.

Alternative 2 differs from Alternative 1 insofar as formation of one or more mutual operating agencies would enhance the region's ability to finance and operate large-scale thermal baseload resources, and BPA would continue its current function of developing and maintaining the Federal high-voltage transmission grid. Thus, the region's need for interregional transactions would be marginally reduced while its institutional and physical capabilities to avail itself of interregional marketing opportunities would be marginally increased. As in Alternative 1, the probability of underbuilding would probably exceed that of overbuilding, but both the propensity to underbuild and the relative probability of underbuilding versus overbuilding would be decreased. Therefore, the operational effects would most likely be those associated with smaller energy deficits (relative to Alternative 1), with some limitations on capability to offset them with acquisitions from other regions.

(d) Alternatives 3 and 4.

These two alternatives differ only slightly in terms of their potential effect on system operations resulting from interregional transaction capabilities and need. Although Alternatives 3 and 4 both include comprehensive regional planning processes, Alternative 4 is assumed to provide somewhat greater regional coordination and probability of load-resource balance than Alternative 3, based principally on the greater centralization and streamlining of planning and decisionmaking authority. Relative to the other three alternatives, Alternatives 3 and 4 would be most likely to ensure a regional balance between resources and loads, and therefore, would be least likely to produce the need to import or export power to offset substantial resource deficits and surpluses. This means that Alternatives 3 and 4 would be likely to have little impact on system operations as a result of need to engage in interregional transactions either to offset resource deficiencies or excesses. On the other hand, if the region determined under Alternative 3 or 4 that it was in the best interests of the Pacific Northwest to acquire power from resources outside the region rather than develop resources of its own, such acquisitions would be facilitated by strong regional coordination.

Improved regional coordination and cooperation under these two alternatives would enhance the region's ability to take advantage of interregional diversities, and would thus improve efficiency in system operations. This increase in efficiency would create a net decrease in adverse environmental impacts. The specific benefits depend on type and terms of the new transactions, and on the amounts of power involved.

e. Nonpower Effects.

Nonpower effects are those effects on system operations resulting from potential changes in water management priorities. Regulation of the Columbia and Snake river system is currently dominated primarily by power requirements, but this priority is being challenged due to increasing competition for water and increasing concern for the impacts of hydraulic and water quality changes. Included among these concerns are the relationship between regulated flows and survival of endangered or threatened species and wetlands habitat. Alternative institutional arrangements for managing the region's electrical energy system would likely have considerable influence on the nature of future water management policies. The level of coordination and participation in decisionmaking, directions in energy resource investment, and prospects for resource sufficiency are all potential factors.

(1) Power - Nonpower Conflicts.

(a) The Role of Hydroelectric Generation.

Hydroelectric generation is unique with respect to the region's other generating resources in that water, the energy source for hydropower, is a natural resource with many uses. Harnessing the free-flowing water in a river is necessary not only for the maximum generation of electricity, but for flood control, navigation, large-scale irrigation, and flat-water recreation. Thus, most public water resource development projects have multipurpose objectives. However, no two uses of this impounded water are totally compatible. Moreover, instream uses --including fish, wildlife, wild and scenic river preservation --may be severely impacted by the construction and operation of such projects. Some resources, such as wetlands, are impacted simply by changes in water levels and flow patterns.

In the case of Federal water resource developments, the potential conflicts between project purposes are partially accommodated both in project design and in the operating arrangements which follow, as dictated by the authorizing legislation. Private projects have fewer obligation to accommodate diverse demands on the water resource. As pressures increase on the fixed resource, even relatively compatible water uses can come into conflict, witness the growing competition between power and irrigation uses on the Columbia and Snake Rivers.

Water resource conflicts in the Pacific Northwest stem from three primary sources: (1) a limited total amount of water subject to increasing demands; (2) incompatibilities between uses with respect to the timing and distribution of water flows; and (3) differing water quality requirements. Although electric generation is not a "consumptive" water use like irrigation withdrawals, power operations do require not only seasonal but daily flow regulation to shape generation to loads. These storage and discharge cycles conflict with hydraulic requirements of the ecosystem and other human uses or values of water. They also contribute to alteration of the physical and chemical properties of the water resource (Role DEIS: A, III).

(b) Fisheries and Irrigation Water Demands.

The principal nonpower water demands likely to produce conflict in the foreseeable future are anadromous fisheries and irrigation, as reflected by the level of controversy each has recently generated in the region. Because both have been investigated extensively, much is known about how hydro operations affect these two areas and what changes in river regulation fisheries and irrigation interests are seeking. Consequently, more is known about what the effects on power production would be were these concerns accommodated. Other nonpower resources--including riparian wildlife, some types of recreation, and aesthetics--may prove to be equally important, but because less is known of their specific relationships to power production, it is more difficult to speculate on the relative probabilities that a given alternative might lead to greater or lesser accommodation by utilities or the region generally.

The environmental and socioeconomic consequences deriving from greater accommodation of fishery and irrigation water needs would entail a series of tradeoffs, not only between power and nonpower uses, but also between fisheries and irrigation. An increase in operational constraints to accommodate anadromous fishery demands would include enhancement of seasonal flow during the downstream spring migration of juveniles, minimum average daily flows (including spill), and restrictions on the magnitude or frequency of reservoir tailwater and forebay fluctuations. Additional measures could be taken to improve water quality. These efforts would contribute to species survival or maintenance of fish populations, which in turn would help preserve a food protein source, fisheries employment, recreational opportunities, and cultural values. Seasonal minimum flow requirements for fish could reduce the firm energy capability of the hydro system in all water years. Daily minimum flows and limits on tailwater and forebay fluctuations could restrict both its energy and load following capability. If generation replacement was necessary, average power costs would likely be higher. The cost of hydro power generation would increase if project owners were to invest money for water quality mitigation measures. Potential loss of revenues from hydro secondary and surplus sales due to spillage would also tend to increase power costs, in addition to increasing the environmental impacts of thermal generation both within and outside the region.

Irrigators are now seeking assured seasonal allocations of water from specific reaches of the Columbia, Snake, and tributary rivers. Such allocations would contribute to an increase in employment, income, and food or forage production dependent on irrigation. The magnitude of these allocations would directly affect both the energy capability of the system and electricity demands (for pumping) on the system. Greater irrigation withdrawals could reduce minimum flows and otherwise restrict system flexibility to satisfy fishery needs.

(2) <u>Power-Nonpower Decisions</u>.

In the absence of a comprehensive river management policy and authority, administration of the Columbia and Snake Rivers has been relegated largely to those entities with the mission of harnessing water for power, navigation, flood control, and irrigation. Other uses, for which engineering structures and hydraulic regulation may be detrimental, have tended to be accommodated only to the extent they do not interfere with project purposes. This unequal emphasis in river management is no longer a stable relationship. Competition for water allocations has intensified to the point that, from the viewpoint of energy planners, uncertainty as to the future availability of water for generating electricity has become a significant variable in the planning process, hence the need to assess its potential significance in the context of alternative institutional scenarios.

For purposes of discussion, the proposal and alternatives affect nonpower decisions in three distinct ways: (1) as a function of the overall degree of regional participation and coordination in energy planning and water resource management; (2) as a function of specific decisions regarding the regional power system, such as resource technologies, interregional transactions, transmission development, and power sales; and (3) as a function of the prospects for energy resource sufficiency or load-resource balance. Clearly, the three variables are strongly interrelated. The third variable, which in essence describes how successful the region is in meeting its electric energy requirements, is the product of many other variables, including levels of coordination and the specific ways in which the system evolves. Thus, resource sufficiency, in addition to influencing the prospects for accommodating nonpower concerns, also may itself be affected by nonpower decisions. See Sections IV.B.1.c. and IV.D.1.e. for further discussion of this point.

(a) Participation and Coordination.

Greater regional participation in planning the generating system would increase the possibility that nonpower interests would be considered in such planning and accommodated through altered river operations. Interutility coordination in the region would aid utilities and nonpower interests in reaching an agreement which could be implemented in a manner that satisfies both economic and environmental objectives. Especially important among environmental considerations are protection of endangered or threatened species, wetlands, floodplains, wild and scenic rivers and cultural resources that could be impacted. Conversely, the less regional participation and interutility coordination, the less likely that solutions would be reached for accommodating the competing demands of power and nonpower uses of the river. Without such participation and coordinalion in energy planning and river management, legal avenues for satisfying nonpower demands would likely be pursued, resulting in greater political pressures on utilities to accommodate nonpower concerns. However, confrontation and political or legal pressures offer less promise for timely and satisfactory resolution of competing water demands than participatory and coordinated decisionmaking.

(b) Aspects of the Regional Power System.

1. Resource Development.

If the region pursued a program of baseload thermal development, and thereby increased the pressures on the hydro system to follow loads and provide other services for these resources, there would be less flexibility to alter river management priorities. Conservation and load management programs could improve the region's load factor, and would increase the potential for accommodating other water-use requirements. Alternative resource developments would have a less predictable effect on the hydro system. If such resources required load-following capability and backup for intermittent output, power demands on the hydro system might not be reduced, and could even increase, with a corollary adverse impact on system flexibility regarding nonpower river uses. Conversely, to the extent the region had the flexibility to choose from a wide range of energy resources, the more likely it would be able to avoid or minimize conflicts between hydro development and nonpower or environmental consideration. The magnitude of all these effects is dependent not only on the resource mix but also on the rate of growth in resource requirements.

2. Interregional Transactions.

Water management decisions are also influenced by the region's ability to utilize interregional diversities in matching loads and resources. If the region were limited in its ability to acquire additional power to offset resource deficits, system flexibility would be reduced and the uncertainty of resource sufficiency would increase, possibly to the detriment of nonpower uses of the river. On the other hand, the same limitation on ability to market surplus power, in the event of excess generation capacity, could have a beneficial effect on nonpower water uses in that the potential would exist for displacing, for example, some hydro energy in order to allocate more water for other uses.

3. Transmission Development.

Evolution and operation of the regional grid could influence the type of new energy resources selected, and could change the resource integrating requirements placed on the hydro system, which in turn could affect accommodation of nonpower water needs. However, the direction and magnitude of that effect are unpredictable without specification of both the transmission and energy resource changes.

4. Power Sales.

There is a potential indirect effect if DSI loads are not served. The extent to which loss of DSI loads would add to flexibility in system operations for satisfying nonpower demands would depend on how the region optimized the allocation of water between firm sales, secondary/surplus sales, reserves, and nonpower hydro regulations. This mix entails possible impact tradeoffs within the Pacific Northwest between levels of reliability, electrical rates (as a function of reserve costs and secondary/surplus sale revenues), and environmental and socioeconomic impacts associated with power and nonpower river uses. To the extent water was allocated to nonpower uses at the expense of surplus sales, impacts would also accrue outside the region, including power costs, air pollution, and nonrenewable resource consumption as a result of the additional oil-fired generation.

(c) Resource Sufficiency.

In the event that limited regional coordination increased the tendency toward resource insufficiency, existing nonpower constraints might be relaxed over the short term in order to generate additional power. On the other hand, if resource surpluses occurred relative to loads, there is greater likelihood, at least in the short run, that nonpower demands would be accommodated. In other words, the greater the prospect for load resource imbalances, the more uncertain the establishment of a long-term, stable accommodation betwen power and nonpower interests, with a corresponding increase in the likelihood of short-term, *ad hoc* adjustments between the two. In general, nonpower interests are likely to suffer in the face of greater uncertainty regarding the region's ability to ensure timely development of new resources. Loss of DSI loads would adversely impact maintaining minimum streamflows off-peak or water would need to be spilled if a suitable replacement load (i.e., perhaps secondary sale) could not be found.

(3) Comparison of the Proposal and Alternatives.

(a) The Proposal.

Relative to the four alternatives, the proposal constitutes an intermediate scenario with respect to regional cooperation and coordination, with a corresponding intermediate probability that competing water demands might be arbitrated to the mutual satisfaction of major river users.

Two related features of the proposal enhance the prospects for satisfying nonpower demands for water. First is the increased role of BPA in regional resource planning and operation. BPA's participation and coordination vis-a-vis other regional power entities would give the participants greater collective authority to make decisions and implement hydro regulations that could reflect the needs of multiple users. The second is the preparation of a long-range regional planning document, which could serve as an additional focal point for consideration and accommodation of competing water uses. Mitigating against such accommodation is the fact that decisionmaking authority would be vested solely in electric power entities.

Relative to Alternatives 1 and 2, the proposal would seek to broaden the range of potential resource investments in the region; relative to Alternatives 3 and 4, it would lack the means. The proposal might be the least likely to yield investments in resources other than types already available in the region. Thus, strictly on the basis of probable resource developments, the proposal is not very promising as a vehicle for reducing competition for water between power and nonpower users. However, to the extent the proposal would increase the range of resource options available to the region, it also would increase the potential for developing nonhydro resources in order to free water for other uses.

The proposal would provide for no substantial changes from present activities in development and maintenance of the transmission grid, nor would it represent any significant change in the region's ability or need to acquire and sell power outside the Pacific Northwest. However, the region would be likely to have more options available for balancing loads and resources under the proposal than under Alternatives 1 and 2, based on its potential comparative superiority in interregional transmission, marketing capabilities, and planning coordination. Thus, in terms of this factor alone, the potential under the proposal for additional consideration of nonpower water uses in the management of the Columbia and Snake river system is unchanged compared to the present, but substantially improved relative to the first two alternatives.

The proposal would create considerable uncertainty regarding future DSI service. If DSIs were to be served as retail loads, hydro operations would be directly affected, possibly to the detriment of some nonpower uses. However, if DSIs were no longer to be served by BPA or the region's utilities, there might also be an indirect effect on system operations as a result of the opportunity to decide how to allocate or use the water once committed to the DSIs. It is perhaps equally likely under Alternatives 1 and 2 and the proposal that BPA would develop an allocation policy which would not provide Federal power to those of its preference customers who assumed service to current DSI customers once the industries' contracts with BPA expired. Alternatives 3 and 4 stipulate continued service to existing DSIs. Thus, with respect to this factor, the proposal (and the first two alternatives) create the potential for substantial change from the present in terms of an opportunity to reallocate some additional water for nonpower purposes.

The proposal occupies an intermediate position in the range of load-resource balance probabilities. As such, it has a corresponding probability of producing long-term, stable accommodation between power and nonpower interests. In other words, the proposal is less likely than Alternatives 1 and 2, but more likely than Alternatives 3 and 4, to result in uncertainties regarding resource sufficiencies, hence short-term, *ad hoc* arrangements for meeting nonpower needs are likely.

(b) Alternative 1.

Alternative 1 represents the lowest level of regional coordination among the five alternatives. It contains no provision for broad-based regional participation in power resource decisionmaking. In light of these considerations, Alternative 1 offers little promise that management of the region's water resources would satisfactorily accommodate nonpower concerns.

Alternative 1 includes no regional mechanism for financing large, expensive generating resources, although this would not prevent two or more utilities from entering into cooperative ventures to develop such resources. Based on capability alone, however, the probability of Pacific Northwest utilities constructing substantial numbers of large, thermal baseload resources is small relative to the other four alternatives. This could mean that under Alternative 1 the region's utilities would find it necessary to construct smaller-sized plants, utilizing conventional technologies not yet employed extensively in the Pacific Northwest. The implications of this resource scenario on nonpower demands probably would not be very different than with the existing resource mix. Combined with limited coordination and likelihood of load-resource imbalances, the prospect for accommodating such demands would be unlikely to improve, and could deteriorate.

Although BPA would continue to function as a broker for the region in transacting power sales, purchases, and exchanges outside the Pacific Northwest, cooperation and coordination in the region would probably be sufficiently reduced so as to limit BPA's effectiveness in this capacity. Inability to take full advantage of interregional diversities and the economies of single entity transactions would reduce overall efficiency in system operations.

The region also would be inhibited in any efforts to upgrade existing segments of the regional transmission grid and interties. To construct additional regional and interregional connections would probably necessitate creation of one or more new non-Federal entities. These conclusions derive from the fact that this alternative specifies amendment of the Federal Columbia River Transmission System Act to remove from BPA the authority to effectively utilize the Federal transmission system to facilitate future resource development or further integration of the regional grid with interregional connections. Aside from possible effects on resource development *per se*, it could result in a potential physical limitation on interregional transaction capabilities. To the extent these limitations contributed to greater uncertainty regarding load-resource balance, the potential for a stable balance between competing water uses would be decreased.

The uncertainty over future DSI service under Alternative 1 would be essentially the same as under the proposal. This uncertainty would create the potential for additional water to be made available for nonpower purposes.

Given a minimum level of coordination, constraints on resource financing, and institutional limitations on the region's ability to engage in interregional transactions, Alternative 1 would be the most likely among the five alternatives to result in load-resource imbalances, especially resource deficits. The ability of individual regional entities to take advantage of Federal peaking resources could be impaired. The net effect would be to create considerable uncertainty and instability regarding river-related power needs, with a corresponding negative effect on the potential for achieving long-term balance in multiple-use management of the Columbia and Snake river system.

(c) Alternative 2.

Alternative 2 would provide marginal improvement over Alternative 1 in terms of prospects for accommodating nonpower concerns. The creation of mutual operating agencies (MOAs) for the development and operation of new generating resources, continuation of BPA's existing role in constructing and maintaining the Federal high-voltage transmission grid, and its more active role in planning and coordination, would have the cumulative effect of increasing the region's overall level of coordination and improving its physical and institutional capabilities to engage in interregional transactions.

Whereas creation of the MOAs would increase the feasibility of constructing large baseload plants, which place known demands on the Federal hydro system for load factoring and backup services, these same entities, together with BPA, would also provide a focal point for nonpower interests to apply pressure for an equitable resolution of competing power and nonpower water demands. The relative improvement in the prospects for load-resource balance, and reduced uncertainty of being able to offset resource deficits and surpluses with power imports and exports, would have the effect of increasing the potential for establishing a stable accommodation between competing water users.

(d) Alternative 3.

Under Alternative 3 the potential would be considerably higher for achieving balanced water resource management on the Columbia and Snake river system than under the proposal or the first two alternatives. This prospect derives essentially from three related characteristics of the alternative: (1) creation of a formalized regional planning process; (2) broadly representative participation in regional decisionmaking; and (3) reduced probability of load-resource imbalances.

Creation of the institutional apparatus for regional power production planning, together with more direct public participation via the advisory councils, not only would provide a forum for consideration of water resource management goals and methods, but would give greater voice to nonutility perspectives on the issue. Emphasis here, however, is on the potential, not the probability, for reducing water resource competition and power related impacts. To the degree regional energy decisionmaking becomes centralized rather than fragmented, a political pressure point is created which all concerns, not just nonpower interests, can utilize to advantage. It also means that whatever course of action is chosen has far reaching implications for the region. Thus, depending on the severity of the region's energy problems, those responsible could impose drastic solutions on the region, which within the limits of their mandate, intentionally sacrificed other values in order to ensure energy sufficiency in the Pacific Northwest. These sacrifices could include nonpower values.

On the other hand, to the extent regional councils were to become a significant factor in the decisionmaking process, there also arises the possibility of some internal divisiveness and indecision as a result of many competing interests lobbying for favor. However, the creation of a formalized regional planning process, with its schedules and review procedures, would provide an orderly mechanism for deriving solutions. Without such an institutional apparatus the region would be much less likely to have the opportunity to resolve its water management issues.

The conclusion that the Pacific Northwest would stand a greater chance of achieving load-resource balance under

Alternative 3 than under the preceding three alternatives is based on the anticipated combined effects of improved coordination in planning and operation of the regional power system, and increased ability to finance new resource construction, pursue a wide range of resource investments, develop adequate high-voltage transmission capacity, and effectively take advantage of interregional transaction opportunities. The net effect of greater predictability in matching resources to loads would be to reduce uncertainty as to how much water could be made available at specified times to meet other water demands. It would create an environment in which long-term, stable accommodations between power and nonpower water requirements could be achieved.

(e) Alternative 4.

Alternative 4 differs very little from Alternative 3 except that creation of a Commission to determine regional energy policy and programs, with BPA as the implementing agency, would produce a more highly streamlined entity for managing the regional power system. This would have the effect of further centralizing regional decisionmaking authority. Therefore, to the extent resolution of power-nonpower water demands were sought, a solution would be more likely to be reached. However, to the extent difficult energy decisions were required, it would be easier for a powerful regional Commission together with BPA to exercise its will, and if it so determined, sacrifice nonpower water demands to ensure energy sufficiency. Thus, the institutional arrangements which seem necessary to reduce the risks of load-resource imbalances, could become either an obstacle or an ally to competing uses for the region's water resources.

2. Energy Conservation.

a. Introduction.

As discussed in Chapter III, in developing and carrying out conservation policies and programs, BPA defines energy conservation to be management of the production, distribution, and use of energy to minimize consumption of scarce resources, to increase technical efficiency, and minimize cost.

This broad definition includes actions and programs which cut across the full spectrum of BPA functions and activities. Although BPA recognizes that energy conservation must be interpreted broadly, administratively this definition has been limited within the BPA organization. For the purposes of the Energy Conservation Section established in BPA and this EIS, conservation is considered to include only increases in end-use energy efficiency and displacement of centrally generated electricity through development of renewable resources at point of end-use.

Under this limited definition, certain aspects of conservation are not included within BPA's Conservation Section or this EIS. For example, reductions in transmission line losses, although conservation, are not considered, nor is the large scale development of central station renewable resources. The following discussion of conservation thus reflects this restricted definition.

To determine how much conservation could be accomplished or, in retrospect, how much actually has been accomplished requires accurate knowledge of how much energy would have been consumed in the absence of conservation efforts. This in turn requires either: (1) an accurate forecast of consumption by type of end-use, which assumes no conservation; or (2) accurate knowledge of how energy is actually being consumed for each use, as a basis for estimating how much would have been consumed in the absence of specific conservation measures. Neither is currently available.

While the magnitude of conservation accomplished to date is not known with any degree of precision, there is reason to believe that annual energy consumption in the region currently is roughly 5 to 10 percent less than it would have been without conservation. This rough estimate is based on consideration of the following factors.

In the 1970's, the region experienced a recession, a number of industrial strikes, a short-term fuel shortage, two severe droughts, and high rates of inflation. In addition, it entered into an age of high-cost thermal electric energy. All of these conditions produced large increases in the cost of electricity to ultimate consumers and tended to suppress the rates of growth in energy consumption relative to earlier periods. In addition to the conservation induced by dramatic increases in the cost of energy, there has also been a heightened awareness of the need for conservation, which in turn has produced additional voluntary reductions in energy use. The net effect of these conditions has been to reduce long-term compound rates of annual growth from the 6 percent level of the 1960's to about a 4 percent level in the 1970's. It is virtually impossible, however, to isolate how much of this reduction is due to conservation as a result either of higher energy prices or of specific Federal, State, or utility conservation programs. Thus, valid quantitative analysis of BPA's conservation proposal impacts on overall energy demand and supply is not possible at this time. Tables IV-52 and IV-53 show a number of probable qualitative impacts which can be identified.

TABLE IV-52

DIRECTION OF PRIMARY IMPACTS OF CONSERVATION PROGRAMS ON BPA WHOLESALE CUSTOMERS

ENERGY

Customer Type	Quantity Demanded: Proposal	Quantity Demanded: Alternatives 1 and 2[2/]	Quantity Demanded: Alternatives 3 and 4[2/]	Resources Purchased from BPA: Proposal	Resources Purchased from BPA: Alternatives 1 and 2[2/]	Resources Purchased from BPA: Alternatives 3 and 4[2/]	Other Resources: Proposal	Other Resources: Alternatives 1 and 2[2/]	Other Resources: Alternatives 3 and 4[2/]
Requirements Utility									
Participating[1/]	-	+[4/]	-	-	+[4/]	-	0	0[4/]	0
Nonparticipating	0	0	0	0	0	0	0	0	0
Nonrequirements Utility									
Participating[1/]	-	+[4/]	-	+[5/]	-[4/][7/]	-	-	+[4/]	0
Nonparticipating	0	0	0	+[5/]	-[7/]	0	-	+	0
Industrial									
Participating[1/]	-[3/]	+[3/][4/]	-[3/]	-[3/]	+[3/][4/]	-[3/]	0[3/]	0[3/][4/]	0[3/]
Nonparticipating	0	0	0	0	0	0	0	0	0
Net Effect	-	+	-	0[6/]	0[6/]	-	-	+	0

TABLE IV-52 (continued)

DIRECTION OF PRIMARY IMPACTS OF CONSERVATION PROGRAMS ON BPA WHOLESALE CUSTOMERS

COSTS

Customer Type	BPA Rates[8/]			Direct Costs[9/]			BPA Incentives & Rewards[10/]			Average Cost		
	Proposal	Alternatives 1 and 2[2/]	Alternatives 3 and 4[2/]	Proposal	Alternatives 1 and 2[2/]	Alternatives 3 and 4[2/]	Proposal	Alternatives 1 and 2[2/]	Alternatives 3 and 4[2/]	Proposal	Alternatives 1 and 2[2/]	Alternatives 3 and 4[2/]
Requirements Utility												
Participating[1/]	+	-[4/]	-	+	-[4/]	+	(-)	(+)[4/]	(-)	0	0[4/]	-
Nonparticipating	+	-	-	0	0	0	0	0	0	+	-	-
Nonrequirements Utility												
Participating[1/]	+	-[4/]	-	+	-[4/]	+	(-)	(+)[4/]	(-)	-	+[4/]	-
Nonparticipating	+	-	-	0	0	0	0	0	0	-	+	-
Industrial												
Participating[1/]	+	-[4/]	-	+	-[4/]	+	(-)	(+)[4/]	(-)	0	0[4/]	-
Nonparticipating	+	-	-	0	0	0	0	0	0	+	-	-

1/ Participating in BPA conservation programs.
2/ Compared to proposal.
3/ Assumes industrial customers would not retain all energy savings for increased production and would not increase non-BPA purchases.
4/ Would have participated in BPA conservation programs with the proposal.
5/ Purchases from BPA would be increased by amount equivalent to reductions in purchases by other customers.
6/ Assumes no change in BPA sales as result of conservation programs (no change in resources marketed by BPA).
7/ Purchases from BPA would be reduced by amount equivalent to relative increases in purchases by other customers.
8/ Assumes strict average-cost pricing continued as at present.
9/ Direct costs of BPA programs, other than BPA rates.
10/ Incentives and rewards provided by BPA to offset higher BPA rates, reduced retail sales, and direct costs of BPA programs. (-) denotes reduced net costs (increased BPA incentives and rewards).

DIRECTION OF IMPACTS OF CONSERVATION PROGRAMS ON ULTIMATE CONSUMERS

	ENERGY DEMAND			COSTS: Rates 3/			COSTS: Direct Costs			COSTS: BPA Incentives			COSTS: Net Costs		
Ultimate Consumer Types	Proposal	Alternatives 1 + 2 1/	Alternatives 3 + 4 (Case 2) 1/	Proposal	Alternatives 1 + 2 1/	Alternatives 3 + 4 (Case 2) 1/	Proposal	Alternatives 1 + 2 1/	Alternatives 3 + 4 (Case 2) 1/	Proposal	Alternatives 1 + 2 1/	Alternatives 3 + 4 (Case 2) 1/	Proposal	Alternatives 1 + 2 1/	Alternatives 3 + 4 (Case 2) 1/
Conserving Consumers Served by:															
Participating Requirements Utility	-	+2/	-	0	02/	-	+	-2/	+	(-)4/	(+)2/5/	(-)5/	-	+2/	-
Nonparticipating Requirements Utility	-	+	-	+	-	-	+	-	+	0	0	0	6/	6/	6/
Participating Nonrequirements BPA Customer Utility	-	+2/	-	-	+2/	-	+	-2/	+	(-)4/	(+)2/5/	(-)5/	-	+2/	-
Nonparticipating Nonrequirements BPA Customer Utility	-	+	-	-	+	-	+	-	+	0	0	0	-	+	-
Nonconserving Consumers Served by:															
Participating Requirements Utility	0	02/	0	0	02/	-	0	02/	0	0	02/	0	0	02/	-
Nonparticipating Requirements Utility	0	0	0	+	-	-	0	0	0	0	0	0	+	-	-
Participating Nonrequrements BPA Customer Utility	0	02/	0	-	+2/	-	0	02/	0	0	02/	0	-	+2/	-
Nonparticipating Nonrequirements BPA Customer Utility	0	0	0	-	+	-	0	0	0	0	0	0	-	+	-

1/ Compared to proposal.
2/ Would have participated in BPA programs with the proposal.
3/ From Table IV-11, "Average Cost" columns; assumes strict average-cost pricing at retail level.
4/ Direct incentives permitted by existing authority.
5/ Direct incentives permitted by modified authority, (+) denotes higher net costs (reduced incentives and rewards).
6/ Cannot be determined without further analysis.

(1) Proposal.

With respect to energy conservation, BPA's proposal represents a significantly more active and more systematic approach than BPA has taken in the past. The general course of action, 14-point policy, and types of specific programs discussed in Section B.1.e. of Chapter III would result in substantially more conservation of electric energy in the region than would occur if BPA continued its past role in regional conservation. As a result, total regional electric energy consumption would be less than it would be with a continuation of BPA's past role; regional generation, with its associated impacts (as described in part A and B of this chapter), would in turn be relatively less than otherwise. Impacts of conservation, such as production of materials installation, and operation of conservation devices, would increase.

Most of the increase in regional energy conservation which would result from BPA's proposal would occur in the service areas of BPA customer utilities, as electric energy consumers in those areas responded to BPA conservation programs implemented through the utilities. The increase in energy conservation would ultimately result from BPA programs in three ways: (1) increased response to conservation programs already available in BPA utility customers' service areas, due to greater incentives or enhanced information provided by BPA; (2) expanded availability of conservation programs previously available only in the service areas of a portion of BPA utility customers or in areas served by utilities which were not BPA customers; and (3) availability of new conservation programs developed entirely as a result of BPA conservation efforts.

Because of the general nature of the proposal and a current lack of useful data related to regional energy consumers and uses, it is virtually impossible to determine with confidence how much energy conservation potentially or actually could be accomplished in the region if BPA's proposal were realized, and how much of what would be accomplished with the proposal could be attributed to the proposal itself rather than to other, non-BPA, programs.

(2) Alternatives 1 and 2.

Alternatives 1 and 2 would each result in less conservation of electric energy in the region than would occur with the proposal. As a result, total regional electric energy consumption would be more than it would be with the proposal; and regional generation, with its associated impacts, would in turn also be greater. Impacts of conservation measures themselves would be less.

(3) Alternatives 3 and 4.

Alternatives 3 and 4 would each result in substantially more conservation of electric energy in the region than would occur with the proposal. As a result, total regional electric energy consumption would be less than it would be with the proposal, and regional generation, with its associated impacts, would in turn be less. Impacts of conservation measures would be greater.

The effects of Alternative 4 would be similar in direction, if not in magnitude, to those of Alternative 3. The effects, however, would occur regionwide, since all utilities would be included in BPA programs. Impacts of conservation are discussed below for two possible cases: Case 1, the BPA proposal except for conservation as under Alternatives 3 or 4; and Case 2, Alternatives 3 or 4 for all elements.

b. Energy Availability.

(1) Proposal.

Since BPA's proposal includes no new long-term acquisition of non-Federal resources, BPA would not be increasing its power sales significantly in the future. However, BPA could probably sell all the firm power it could acquire under any of the recent projections of future regional energy demands. Taken together with the anticipated continued useful life of the existing Federal resources and existing contractual obligations to acquire output from certain non-Federal resources, this ability to sell all the power it could acquire suggests that BPA would not reduce power sales in the future either, regardless of the amount of conservation which resulted from BPA's proposal or from other conservation programs.

Thus, while conservation would probably not change the absolute quantity of power available for purchase from BPA, it would reduce the quantity of power that BPA customer utilities would have to acquire from other sources lessening the need for and impacts of those sources. As a result, BPA power sales would represent a larger portion of total regional power consumption than otherwise.

(2) Alternatives 1 and 2.

Since Alternatives 1 or 2 do not include new long-term acquisition of non-Federal resources, BPA would not be increasing its future power sales significantly. BPA would probably not reduce power sales in the future either, regardless of the amount of conservation.

However, while conservation under Alternatives 1 or 2 would probably not change the absolute quantity of power available for purchase from BPA, they would increase the quantity of power that BPA customer utilities would have to acquire from other sources, compared to the conservation proposal, increasing the need for and impacts of those sources, or increasing the impacts of deficits if sources of additional power were not available. With Alternatives 1 or 2, BPA power sales would represent a smaller portion of total regional power consumption than with the proposal.

(3) Alternatives 3 and 4.

(a) Case 1.

BPA's proposal includes no new long-term acquisition of non Federal resources. If BPA adopted this proposal in resource acquisition, but conservation as presented under Alternatives 3 or 4, BPA would not reduce its own power sales in the future regardless of the amount of conservation. The results would be the same as under the proposal.

(b) Case 2.

Alternatives 3 and 4 include acquisition of additional resources on a long-term basis. If either of these alternatives in resource acquisition were adopted, conservation under Alternatives 3 or 4 would result in reductions in power acquired and sold by BPA, compared to the conservation proposal (although more power would be acquired and sold by BPA than with Case 1). Impacts of generation would be reduced; impacts of conservation measures would be increased.

c. BPA Rates.

(1) Proposal.

Since BPA would sell the same quantity of power with the proposal as it would if it continued its past role in regional conservation, but would have costs reflecting the costs of conservation programs, BPA average revenue requirements would have to be somewhat higher with the proposal than with a continuation of its past role, but total costs for its consumers and the region should be less. Assuming BPA continued its present rate policy (i.e., average-cost pricing), this would result in an across-the-board increase in BPA rates of the same magnitude as the increase in required average revenues. However, BPA rates would be less than they would be if BPA were to purchase new thermal generating resources in lieu of investing in cost-effective conservation, since by definition cost-effective conservation would be cheaper than new thermal power. While the relatively higher BPA rates with the proposal would result in price signals for most utilities and consumers which more closely reflected the costs of additional energy from new resources than do present rates, some utilities which do not purchase their entire energy requirements from BPA (nonrequirements utilities) would pay a lower average price for total energy purchases, because the increased BPA rates would be offset by the fact that they could reduce their purchases of other, even higher-priced, resources. (Under BPA's current authority to acquire power resources, all customers will ultimately need to obtain additional supplemental power from non-BPA resources.)

(2) Alternatives 1 and 2.

Since BPA would sell the same quantity of energy with Alternatives 1 or 2 as it would with the proposal, but would have relatively lower costs associated with conservation programs, BPA average revenue requirements could be somewhat lower with Alternatives 1 or 2 than with the proposal. Assuming BPA continued its present rate policy of average-cost pricing, this would result in lower BPA rates, by the same magnitude as the reduction in required average revenues compared to the proposal. BPA rates would be less than the cost of energy from new thermal generating resources by an even greater amount than with the proposal. However, for nonrequirements utilities, the lower BPA rates would be offset by the fact that they would have to purchase a greater quantity of more costly non-BPA power. The relatively lower BPA rates with Alternatives 1 and 2 would result in rates which less closely reflected the costs of additional energy from new resources.

(3) Alternatives 3 and 4.

(a) Case 1.

If BPA sold the same quantity of power with conservation under Alternatives 3 or 4 as it would with the proposal but had higher costs associated with conservation programs, BPA average revenue requirements also would be higher. Assuming BPA continued its present rate policy of average-cost pricing, this would result in higher BPA rates, by the same magnitude as the increase in required average revenues. However, BPA rates would be significantly less than the cost of power from new thermal generating resources, since they would reflect the average of low-cost hydroelectric power and cost-effective conservation. The higher BPA rates with conservation under Alternatives 3 or 4 would result in price signals for most utilities and consumers which more closely reflected the costs of additional power from new resources. Some nonrequirements utilities would pay a lower average price for total power purchases, because the increased BPA rates would be offset by the fact that they could reduce their purchases of other higher-priced resources.

(b) Case 2.

If BPA could acquire additional resources on a long-term basis, conservation under Alternatives 3 or 4 would reduce the amount of additional resources it would have to acquire. Since the increase in costs of conservation would not be as great as the associated reduction in costs of acquiring other resources, BPA rates would be less than they would be if BPA could acquire additional resources but was limited to the proposal or to Alternatives 1 or 2 in the area of conservation programs, although BPA rates would probably be higher than with Case 1.

d. BPA Customers.

(1) Proposal.

The impacts of BPA's conservation proposal on customer utilities participating in conservation programs would be of several types: (1) indirect costs (i.e., a rate structure reflecting costs of BPA programs); (2) direct costs (e.g., additional staff or capital investment); (3) decreases in retail sales; (4) decreases in acquisition of non BPA energy by some nonrequirements utilities; (5) increased production efficiency for DSIs; and (6) incentives and rewards provided by BPA to participants in its conservation programs to offset potentially negative impacts of conservation resulting from (2) and/or (3) above. Each BPA customer would be affected by several of these types of impacts at the same time. Without analysis of specific programs, it is not possible to calculate quantitatively what the net effect on each customer would be; however, the probable direction of the impacts on several general categories of BPA customers can be determined, as shown in Table IV-52.

Table IV-52 shows that BPA utility customers which participate in its conservation programs would have lower power demands as a result. Requirements utilities (i.e., generally, small-to-medium size utilities serving rural areas or small cities and towns) would purchase less power from BPA than they would purchase if BPA were to continue its present role in conservation. Industrial customers would likely purchase the same amount of power (within present sales contracts), but the opportunity to increase production through efficiency improvements would serve as an incentive for conservation. Since the total amount of BPA sales would not be significantly different, nonrequirements utilities (i.e., utilities with generating resources and other large publicly owned utilities, generally serving larger cities and suburban areas) would be able to purchase relatively more from BPA and therefore would need to acquire fewer additional resources. The direct and indirect costs resulting from BPA conservation programs would be partially or entirely offset for utility participants by specific conservation incentives and/or rewards provided by BPA. The net effect of all of these impacts of BPA's proposal, given the assumptions stated in the footnotes to the table, would likely be that the average cost per unit of energy purchased would be relatively higher for nonparticipating industrial customers and requirements utilities, relatively unchanged for participating industrial customers and requirements utilities, and relatively lower for both participating and nonparticipating nonrequirements utilities. However, total costs could be lower due to reduced amounts of power purchased. For most utility customers, these impacts could be expected to be influential incentives for participation in BPA conservation programs.

(2) Alternatives 1 and 2.

Compared to the proposal, the impacts of Alternatives 1 or 2 on BPA's customers would be of several types: (1) lower indirect costs; (2) lower direct costs (e.g., relatively less staff or capital investment); (3) increased retail sales; (4) increased acquisition of non BPA energy by nonrequirements utilities; (5) lower production efficiency for DSIs; and (6) fewer incentives and/or rewards provided by BPA to participants in its conservation programs.

The probable direction of the impacts on several general categories of BPA customers can be determined, as shown in Table IV-52. The table shows that BPA customers who would have participated in its conservation programs with the proposal would have higher power demands with Alternatives 1 or 2. Requirements utilities would purchase more energy from BPA with Alternatives 1 or 2. Since the total amount of BPA sales would not be significantly different with Alternatives 1 or 2 than with the proposal, nonrequirements utilities would be able to purchase less from BPA and would therefore need to acquire additional resources. The net effect of all of these impacts of Alternatives 1 or 2, given the assumptions stated in the footnotes to the table, would likely be that the average cost per unit of energy purchased from BPA would be relatively lower for industrial customers and requirements utilities which wouldn't have participated in BPA programs with the proposal, relatively unchanged for industrial customers and requirements utilities which would have participated in BPA programs with the proposal, and relatively higher for nonrequirements utilities, regardless of whether they would have participated in BPA programs with the proposal.

(3) Alternatives 3 and 4.

The impacts of conservation under Alternatives 3 or 4 on BPA's customers would be of several types: (1) changes in the indirect costs of BPA programs; (2) greater direct costs; (3) decreases in retail sales; (4) in some cases, decreases in acquisition of non-BPA energy by nonrequirements utilities; (5) greater production efficiency for DSIs; and (6) greater incentives and rewards provided by BPA to participants in its conservation programs.

Table IV-52 shows that BPA customers which participated in its conservation programs would have lower power demands as a result. Participating industrial customers and utility customers would purchase less energy from BPA, and the total amount of BPA sales would also be less. The amount of other resources acquired by these utilities would be the same as a result. Conservation as under Alternatives 3 or 4 would result in lower BPA rates for all BPA customers. Reduced sales and direct costs of BPA conservation programs would be partially or entirely offset for participants in conservation programs by specific conservation incentives and/or rewards provided by BPA. The net effect of all of these impacts of conservation under Alternatives 3 or 4 would likely be that the average cost per unit of energy would be relatively less for all BPA customers.

e. Ultimate Consumers.

(1) Proposal.

Ultimate consumers would be affected by BPA conservation programs resulting from the proposal in a number of ways: (1) reductions in power used; (2) increases in electric rates; (3) direct costs of conservation measures (i.e., installation costs); and (4) incentives and/or rewards provided to consumers participating in BPA utility programs to help offset the impact of (2) and (3) above.

Table IV-53 shows that most consumers who adopted conservation measures as a result of BPA conservation programs under the proposal would have lower net costs for electric power than if they did not conserve. Consumers who adopted conservation measures and who were served by nonparticipating requirements utilities might also have lower costs depending upon the magnitude of their power savings and costs of conserving; those consumers who did not adopt conservation measures would have higher costs. These impacts would encourage consumers to adopt conservation measures.

Table IV-53 also shows that consumers served by nonrequirements utilities who did not adopt conservation measures would have lower net costs than they would be without BPA's conservation proposal, but not as low as if they also conserved. Consumers who did not adopt conservation measures and were served by participating requirements utilities would have neither higher nor lower costs.

Those consumers shown in Table IV-53 to be relatively better off (i.e., a negative sign in the Net Costs column) would have more disposable income to spend on nonenergy goods and services (if residential consumers) or lower costs of doing business (if commercial or industrial consumers). Those consumers shown in the table to be relatively worse off (i.e., a positive sign in the Net Costs column) would have less disposable income to spend on nonenergy goods and services or higher costs of doing business.

(2) Alternatives 1 and 2.

Ultimate consumers would be affected by Alternatives 1 or 2, compared to the proposal, in a number of ways: (1) increases in energy consumption for participating consumers; (2) decreases in electric rates for consumers served by some BPA customer utilities; and (3) fewer incentives and/or rewards provided to participating consumers.

The probable direction of the impacts on several general categories of consumer can be determined, as shown in Table IV-53. The table shows that most consumers who adopted conservation measures would be worse off with Alternatives 1 and 2 than with the proposal. Whether consumers who adopted conservation measures and were served by nonparticipating requirements utilities would also be worse off would depend upon the magnitude of their energy savings, retail rate reductions, and costs of conserving; while similar customers who did not adopt conservation measures would be better off. These impacts would tend to discourage consumers from adopting conservation measures.

Table IV-53 also shows that, of consumers who did not adopt conservation measures, those served by nonrequirements utilities would be worse off with Alternatives 1 or 2 than they would be with BPA's conservation proposal. Consumers who did not adopt conservation measures, and were served by participating requirements utilities, would be neither worse nor better off with Alternatives 1 or 2 than with the proposal.

Those consumers shown on Table IV-53 to be worse off (i.e., a positive sign in the Net Costs column) would have less disposable income to spend on non-energy goods and services (if residential consumers), or higher costs of doing business (if commercial or industrial consumers). Those consumers shown in the table to be better off (i.e., a negative sign in the Net Costs column) would have more disposable income to spend on nonenergy goods and services, or lower costs of doing business.

(3) Alternatives 3 and 4.

Ultimate consumers would be affected by BPA conservation programs resulting from Alternatives 3 or 4 in a number of ways: (1) reductions in energy use by those consumers; (2) changes in electric rates; (3) direct costs of conservation measures (i.e., installation costs); and (4) greater incentives and/or rewards provided to consumers participating in BPA/utility programs. The probable direction of these impacts on several general categories of consumers can be determined. Under Case 1, the direction of the impacts would be the same as with the proposal (Table IV-53). only of greater magnitude. Impacts under Case 2 differ from those of the proposal and Case 1, as shown in the table.

Table IV-53 shows that nearly all consumers would be better off with conservation under Alternatives 3 or 4 than with the proposal. Whether consumers who adopted conservation measures as a result of BPA conservation programs (e.g., public information programs), and were served by nonparticipating requirements utilities, would also be better off would depend upon the magnitude of their energy savings and retail rate increases which ultimately resulted from BPA's conservation proposal, and costs of conserving. Thus, generally, Alternatives 3 and 4 would encourage consumers to adopt conservation measures.

Those consumers shown on Table IV-53 to be better off (i.e., a negative sign in the Net Costs column) would have more disposable income to spend on nonenergy goods and services or lower costs of doing business.

f. Other Impacts.

For a discussion of the environmental impacts of conservation measures, see Part B of this chapter.

(1) Proposal.

In addition to the general impacts summarized in (2)-(5) above, BPA's conservation proposal would also tend to increase employment and sales in the building materials, conservation equipment, and installation industries as well as the environmental impacts of the operation of these industries. These increases would be distributed throughout the region, in communities and rural areas in which BPA conservation programs were successful. These increases could be partially offset by small reductions in employment, economic activity and environmental impacts in a few locations as a result of slowing of construction of some new generating facilities.

(2) Alternatives 1 and 2.

In addition to the general impacts summarized above, Alternatives 1 and 2 would also tend to cause a reduction in employment and sales in the building materials, conservation equipment, and installation industries, distributed throughout the region and a corresponding reduction in the impacts of these industries' operations. These reductions could be partially offset by small increases in employment and economic activity in a few locations as a result of acceleration of construction of some new generating facilities.

(3) Alternatives 3 and 4.

In addition to the general impacts summarized above, conservation Alternatives 3 or 4 would also tend to increase operational impacts, employment, and sales in the building materials, conservation equipment, and installation industries, distributed throughout the region. These increases could be partially offset as under the proposal.

3. Marketing.

a. Customer Services.

(1) Proposal.

Under the proposal BPA would, to the extent of its capability, continue to offer services to regional utilities to integrate new and existing non-Federal generating resources into the FCRPS for their use. This would include resources within or outside the region.

BPA would be precluded from entering into additional long-term agreements for the acquisition of non-Federal power. Consequently the amount of energy and capacity available for services such as load factoring, forced outage reserves, and load growth reserves would limited to the capability of existing and committed resources. There could be a potential loss of operating and planning reserves if BPA's allocation policy resulted in the cessation of service to direct-service industrial customers (DSIs). This would reduce BPA's ability to provide services. Services would be allocated according to the preference given public bodies and cooperatives by law.

The provision of these services would fall increasingly upon individual utilities or groups of utilities, with resulting financial demands on utilities and impacts of facility development on the environment. It is probable that reserves increasingly would be provided by standby generation in the form of combustion turbines, coal-fired generation, etc., which would result in air emission, consumption of fuels, thermal releases, and the other impacts of these types of generation. (See Section IV.B.2.d. for a discussion of generation impacts).

Conservation and load management programs could be used to reduce load growth and increase utility load factors. Impacts of these programs are discussed in Section IV.B.2.a.

As more expensive standby generation was utilized, rates also could be expected to increase, mitigated by sales of any excess energy generated within or outside the region.

(2) Alternatives 1 and 2.

BPA's ability to provide customer services would be diminished under both of these alternatives, particularly in Alternative 1, as no integrating transmission for non-Federal resources would be provided. As with the proposal, cessation of DSI service could reduce BPA's ability to provide customer services to utilities.

Since utilities would be required to fill their own needs for these services, the impacts covered under the proposal would apply.

(3) Alternatives 3 and 4.

BPA would continue to operate as it does currently, providing customer services to all regional utilities so long as the integrity of the power system was not jeopardized. Under Alternative 4, BPA would have a responsibility to provide such services to all of the region's utilities upon request. The provision of such services as load factoring, load growth reserves would be enhanced through efficiencies gained in centralized system planning, development, and operations. Thus, it is likely that the more expensive combustion turbines would have less application as larger more efficient baseload units would probably be utilized, backed by the hydro system. Impacts would include the emission of thermal baseload plants and the impacts of hydro operations to provide services for those plants. Continued service to the DSIs would also guarantee this source of reserves to the regional system. The associated economic and environmental impacts of DSI operations would continue.

Under both Alternatives 3 and 4, BPA would have increased ability to provide wheeling and trust agency power purchases and sales. Under Alternative 4, BPA's larger role could alleviate the need by individual utilities for such services.

The impacts would primarily be the same as under the proposal except it is likely that combustion turbines would have reduced application as larger more efficient baseload units would probably be utilized, backed with the hydro system.

b. Allocations.

BPA will have a limited amount of power available from a fixed number of Federal and non-Federal projects as existing contracts with preference and DSI customers expire. BPA anticipates an increasing number of competing applications from new as well as existing preference agencies for BPA power. Therefore, the allocation issue BPA currently faces is how to distribute a shortage of Federal power among the preference customer class. The proposal and Alternatives 1 and 2 provide scenarios for BPA to allocate or distribute the limited amount of relatively low-cost Federal power. However, the allocation proposal does not solve the power shortage problem. Alternatives 3 and 4 do provide mechanisms for BPA to acquire sufficient resources to serve all preference and nonpreference customers' loads, and also, specify the distribution of power from different rate pools to the varying types of customers. For these reasons Alternatives 3 and 4 do not require a provision for allocation.

Given equal regional loads, the potential for environmental impact is greater under Alternatives 1 and 2 than under the proposal due to uncertainty related to future unknowns, i.e., loads, resources, number of preference utilities, etc., and a greater potential for a regional load-resource imbalance.

As each utility plans individually to meet future loads, the risk of overbuilding increases, based on uncertainty of future Federal power allocations, load forecasts, plant construction schedules, effectiveness of local conservation programs, the economic impacts of underbuilding, and general conservatism related to public utility responsibility. Without a coordinated regional approach to buffer individual utilities through regional "sharing" of the shortage potential, utilities must provide a larger safety margin in their own resource schedules, which results in the impacts of construction and operation of facilities or the impacts of deficits due to reduced firm power capability.

The potential for underbuilding in these alternatives must not be dismissed, however. If a utility decides to rely on a particular technology, and the approach in its individual area is not successful, time will generally not remain to build other new resources. This could result in a shortage. In addition, generating facilities will continue to be more difficult for single or small groups to finance, due to high capital costs and construction uncertainties.

The allocation programs in Alternatives 3 and 4 would resolve many of the questions regarding the amount of Federal power utilities can expect to receive, financing arrangements, load forecasting, etc. This would allow the region to plan future resources more accurately, thereby reducing the potential for load-resource imbalances and associated environmental impacts.

(1) Proposal.

Under BPA's proposed policy (published in the Federal Register on October 5, 1979), BPA will serve both existing and new preference customers (PCs) regardless of the composition of their loads. Direct-service industries (DSIs) and Federal agencies (FAs) however, will no longer be served firm energy directly by BPA, and are expected to apply for service from their local utilities when their current BPAcontracts expire. About half of the customers upon expiration of their BPA contracts will be considered eligible load in determining a PC's allocation. System reserve energy will also be made available to supplement remaining eligible DSI load. The policy will take effect in 1983, but a transition period is provided which guarantees that a utility will receive at least its existing contract base allocation provision until July 1, 1991, at which point the allocations will be determined from a pro rata distribution of energy based on utility net requirements. A sharing of costs and benefits provision is incorporated and a conservation reserve is established. Briefly, the main intent of the proposed policy is to minimize disruption to existing preference customers without discouraging new preference applicants. The transition period between 1983 and 1991 also helps existing preference customers to adjust to the changes which the policy will produce. The reserve capability which the DSIs provide for the region will be continued through policy provisions.

Other major elements of the proposed policy are:

-- It assures that small customers will continue to receive their full requirements through July 1, 1991, and that all other customers will receive at least their present contract base allocation.

-- BPA will offer all customers contracts with a common termination date; because in the past, staggered contract termination dates meant an inability to treat all customers uniformly.

-- Also, there are provisions for those who choose to retain their present contracts rather than sign new ones under the new allocation policy. If an existing contract is kept by a customer, the customer will receive its contractual obligations. However, upon expiration of the contract, the customer will be treated the same as any other new preference customer, which means that it will have only a minimal power supply assurance until 1991.

-- Any new load exceeding 10 average MW will not be eligible for sharing in the Federal power supply.

(2) Alternative 1.

Alternative 1 assumes BPA would make a single fixed allocation of Federal power to existing preference customers. Thus, the current geographic distribution of BPA's preference customers would be maintained, with the State of Washington receiving more FCRPS benefits in proportion to its population than other Northwest states. The relatively low-cost Federal power would be made available to serve all loads of the existing preference customers, although it is not clear whether the DSI loads would be served through preference customers. The impact of this allocation would be a tendency for higher consumption in areas receiving low-cost power, and a corresponding tendency for lower consumption in areas which would have to rely on higher cost power.

If no DSI loads were served by preference customers, the existing preference customers could, as a group, meet their future energy requirements for an extended period into the 1990's. Thereafter, preference customers would meet future energy requirements by first withdrawing increasing increments of their own hydro resource capability from investor-owned utilities to the extent they were able, then by withdrawing their WNP-4/5 thermal resource capability from DSIs, and subsequently, by developing new energy projects, which would have environmental impacts, depending on the technology selected, as described in Section IV.B.2.

Upon expiration of their current BPA power sales contracts, DSIs would be dependent upon firm and nonfirm power available from utilities. Preference utilities and surplus power from WNP-4/5 would be the principal sources of this energy. As the energy requirement of current preference customers increased, BPA would be obligated to sell less firm energy to DSIs. The DSIs would purchase the balance of their requirements, if possible, from other sources including utilities and new energy projects. Those DSIs located within or adjacent to preference customers' service areas might receive service from those preference customers. Those preference customers would then be dependent upon other energy resources to meet their energy requirements as early as the mid-1980's. To the extent that DSIs purchased non-Federal power from utilities, purchased or constructed resource capability to supply their own requirements, or terminated their operation in the Pacific Northwest, regional reserves and other benefits of the DSIs would be lost to the Federal system and its customers. If DSIs provided their own resources, impacts of power generation would result; if they terminated operations, the economic and environmental impacts of their operations would cease.

Investor-owned utilities would be totally dependent on new energy projects for meeting increases in their firm energy requirements. Preference customers which sold their resource capability to investor-owned utilities would withdraw such sales as their energy requirements exceeded their BPA allocations or when their BPA energy became more expensive than the resources sold to investor-owned utilities.

Investor-owned utilities would also be required to serve a greater portion of their current load from new energy projects. PSPL, PGE, WWP, and PP&L are currently purchasing substantial amounts of power from hydro resources developed and owned by preference customers. Therefore, the difference between BPA preference customers' and investor-owned utilities' wholesale power costs and retail rates would rise substantially above current levels, with relatively reduced consumption in higher rate areas compared to those with lower rates.

Under this alternative, there would be little or no assurance of improvement in the load-resource deficits forecasted for the future. No utility or group of utilities could rely on voluntary conservation efforts or undertake the risk of deferring plants and not being able to meet loads.

Public bodies and cooperatives which are currently BPA customers would receive a fixed allocation of BPA power under this alternative. Once all the additional Federal power made available by the termination of the DSI contracts had been allocated, the availability of relatively cheap Federal power would no longer be an incentive to the formation of new preference entities within the region. Consequently, BPA's policy to serve existing preference customers rather than any new preference customers could result in the preference clause operating to prevent any future change in the distribution of FCRPS benefits in the region, specifically, reducing the incentives for forming new publicly-owned utilities. The nonequal treatment of new public bodies and cooperatives could further separate the region into enclaves of the "haves" and the "have-nots."

(3) Alternative 2.

This alternative assumes Federal power would be allocated to meet the total load growth requirements, to the extent possible, of existing and new preference customers within the Pacific Northwest. New publicly and cooperatively owned utilities would be allocated any BPA power that had not been previously committed to existing preference customers and periodic reallocations would be made.

Future preference customers' allocation of BPA's low-cost power and resultant wholesale power costs would depend on the number of preference utilities and also upon preference customers' service to DSIs with the expiration of their power sales contracts with BPA. An increase in allocations from BPA to cover preference customer service to DSIs alone would leave little or no BPA power available for new preference customers or for the load growth of existing preference customers. This assumes that allocations would be fixed rather than floating or changing with time. A floating allocation could continually redistribute the limited supply as needs changed.

Upon the expiration of their new power sales contracts with BPA, DSIs would be dependent upon firm and nonfirm energy sales available from other regional utilities for the short term. Over the long term, such industries would be required to either purchase power from a local utility, arrange with a number of other industrial customers or utilities to construct their own resources, purchase the capability of a resource constructed by an MOA or other regional entity, or cease Pacific Northwest operations. Investor-owned utilities' new energy requirements and power costs would be affected by the number and size of new publicly and cooperatively owned utilities created to take advantage of the available supply of low-cost BPA power. As wholesale power costs of the investor-owned utilities increased further, greater pressure would be generated for creation of new publicly and cooperatively owned utilities which would qualify as preference customers. In planning resources to meet future loads, IOUs would have to take into account the contingency that sizable segments of their service area might be served by a publicly or cooperatively owned utility in the future.

No change in the preference clause is assumed under this alternative, although there probably would be considerable incentive for new preference customers to form. This could result in a wider distribution of preference customers and consequently, Federal power throughout the Pacific Northwest. Efforts to make it easier to form preference utilities would probably be initiated in Oregon, Idaho, and Montana.

(4) Alternative 3.

This alternative assumes BPA would offer to sell Federal power: (1) to all regional utilities for their firm loads in excess of their resources committed to firm load, to the extent that BPA had or could acquire adequate resources; and (2) with a 5-year phasing-in period to participating IOUs for their residential power requirements.

This alternative would enable BPA to acquire a supply of power sufficient to meet all the requirements of preference customers, including the industrial and commercial loads presently served by public power--and thus eliminate the problem of equitably allocating shortages of Federal power among applicants, thus avoiding the impacts of shortages. It would also specify the distribution of power from rate pools of differing costs, thereby eliminating questions regarding allocation of low-cost power.

New preference customers, if formed, could be served at BPA's low regional rate as soon as BPA could acquire adequate resources to meet their loads.

DSIs would continue to receive power based at rates comparable to industries served by distributors with credit for the reserves they provide. While their rates would be substantially higher than currently provided for under BPA contracts, it is anticipated this would allow continued operation of the DSIs, and therefore continuation of their economic and environmental impacts.

BPA would use the Federal hydroelectric and net-billed thermal resources to meet the general requirements of public bodies, cooperatives, and Federal agencies, as well as the residential and small farm loads of the investor-owned utilities. The wider distribution of the relatively low-cost Federal power specified under this alternative could reduce incentives for energy conservation.

No change in the status of preference customers is anticipated by this alternative; i.e., they would continue to have preference to Federal power. However, since adequate resources would be assured for the Pacific Northwest region, the incentive to form new preference customers would be reduced. This alternative would allow a wider distribution of FCRPS benefits in the Pacific Northwest, especially to the residential consumers.

(5) Alternative 4.

The Regional Energy Commission would set the policy for the sale of electric power by BPA. BPA would offer to meet every participant's full requirements, with preference given to publicly and cooperatively owned utilities. Participants with power resources would be required to sell them to BPA. When available, nonfirm and surplus power would be offered to participants. Participants would have to resell this power within their service area to the extent power was available. If the sale would not compromise the integrity or reliability of the system, BPA would offer nonfirm and surplus power for sale to nonparticipants and to utilities outside the region.

To the extent that BPA had adequate resource capability to serve the needs of all regional consumers, the wholesale power cost differences between preference customers and investor-owned utilities would be eliminated. Differences in preference customers' and investor-owned utilities' rates would be a function of other factors affecting operations and cost. The economic advantage in creating a new publicly or cooperatively owned utility to receive an allocation of BPA power would be diminished.

BPA would sell the available Federal hydroelectric and net-billed thermal power in the BPA pool to participants within the Pacific Northwest under the following two categories:

1. Rate I Power.

The lowest production cost for use by the general public, domestic and rural; for energy requirements of units of city, county, and state government; and for the operation of publicly owned transportation systems; and

2. Rate II Power.

All the electric power in the BPA pool in excess of that in the Rate I pool for the use of all the remaining energy consumer demand not met by Rate I energy.

The wider distribution of the relatively low-cost Federal power made available by this alternative could result in less concern for conservation of electric energy, although the mandatory control over each participant's conservation called for as part of this alternative would tend to offset this concern.

No change in the preference clause is expected from this alternative. In addition, there would be little incentive for new preference customers to develop since participating utilities would be able to share resources equally. Federal power would be more equally distributed to end-use consumers throughout the region.

c. Secondary and Surplus Energy.

The amount of nonfirm power generated in the region would not change under the proposal or any of the alternatives, since firm power would be based on the critical water assumption in all cases, and secondary or surplus power is hydro generated power produced by better-than-critical water conditions.

(1) Proposal.

Availability of secondary energy to customers of retail utilities would potentially be increased by the proposal. If, under the proposal, the DSIs ceased to operate within the region, this assured market for secondary energy would be lost. Two effects would result. First, under a situation of limited secondary energy, more secondary energy would be made available to the investor-owned utilities in the region. This could result in the shutdown of thermal generating facilities or the sale of the energy outside the region from those facilities which could not practically or cost-effectively be shut down. Secondly, the regional market for secondary energy would be more quickly saturated, putting the region into a surplus situation and allowing more sales outside the region.

Preference demand for secondary energy might also increase, restricting its availability to the investor-owned utilities, and increasing IOU costs and rates. This would increase the regional retail rate disparity. A possible cause of increased preference demand would be the displacement of future thermal plants during maintenance periods, such as presently done by the IOUs.

(2) Alternative 1.

In addition to impacts such as those indicated under the proposal, transmission limitations of Alternative 1 would also affect the use of secondary energy. As BPA provided less of the region's transmission, some utilities might not find it cost-effective to build additional line capacity to tap into the grid.

(3) Alternative 2.

The impacts of Alternative 2 would be the same as those under the proposal.

(4) Alternatives 3 and 4.

Regional benefits from secondary power energy would be enhanced under Alternatives 3 and 4. Continued service to the DSIs would maximize Northwest use of the secondary energy while providing a portion of the region's reserves.

It is also possible that secondary power could be coordinated with renewable resource development in the region. In this case, the FCRPS would be used as a backup or storage battery for these resources. The Pacific Northwest appears to present excellent opportunities for this, particularly for solar energy. The solar cycle generally complements that of the hydro system. Alternatives 3 and 4 would actively support the development of solar and other renewable resources.

d. Rates.

(1) Proposal.

The proposal embodies all of the rate activities with which BPA is now involved. Current wholesale power and transmission service would continue to be offered through rate schedules comparable to those under which BPA now sells these services. Repayment requirements would be met through a rate structure similar to that which has been proposed by BPA. A discussion of the proposed rate schedules and the probable impacts of those rates is contained in the section on existing rates.

BPA requested a 90 percent increase in its revenues effective on December 20, 1979. Most of the impact was the result of higher rates rather than the actual rate structure (Rate FEIS: V).

In summary, the rate impacts which would result from the proposal of continuing BPA's current role in the Pacific Northwest are as follows:

- -- A 90 percent increase would result in a .9 to 2.8 percent decrease in loads by 1994 below what they would otherwise be without the increase. This is due to a response to the increase in the price of electricity. The decrease in consumption will take the form of conservation and fuel switchovers.
- -- Low-income residential consumers would receive the greatest real impact because a greater portion of their budgets is used for power purchases than is the case for the average-income consumer.
- -- In the industry, heavy power users such as aluminum firms would be impacted significantly because electricity is a larger portion of their cost of production than is the case for other industries.

A rate increase of the magnitude proposed by BPA would result in higher costs for BPA customer utilities. To the extent that these costs were passed on to their customers and in relation to the percentage of each utility's power which was purchased from BPA, the disparity of rates between public and private utilities would be reduced after the BPA rate increase went into effect.

(2) Alternative 1.

A reduction in BPA's authority would have little impact on rates compared with a continuation of existing policy. Costs of the system must be recovered, and to the extent that current hydro and transmission costs were recovered and current net-billing arrangements continued, BPA would still require significant rate increases between 1979 and 1985 to assure the recovery of those costs.

BPA's transmission costs could be lower under this alternative, which would reduce the magnitude of both wholesale power and transmission rate increases. However, since the largest portion of BPA's cost increases between 1979 and 1985 would be due to additional hydro construction and thermal purchases, there would not be a significant reduction in rates from lower transmission costs when compared with existing policy. Moreover, cost increases for operation and maintenance of the existing transmission system would continue. The cost of wheeling services would go down as long as BPA rates were based on average costs, since, with no new transmission construction, only current investment and operation and maintenance costs would be recovered from current wheeling contract services. Rate increases would not result from expansion of wheeling services over the current system.

Those customers with current wheeling contracts, primarily investor-owned utilities, would experience relatively small increases in their transmission rates. However, new transmission facilities would still be required and the cost of new transmission would still have to be recovered from ratepayers of the utilities which needed to expand their transmission system.

(3) Alternative 2.

As with Alternative 1, there appears to be no different rate impacts from this alternative when compared with the existing policy. BPA's costs must be recovered through rate increases, and the rate increases necessary under this alternative are very close to what they would be under the proposal. Ratepayers eventually must pay for the costs of the transmission services they receive, whether provided by BPA, a publicly owned utility, or an investor-owned utility.

Incremental transmission costs would increase less rapidly than incremental generation costs. As a result, the transmission component would become a smaller portion of the total cost of power.

(4) Alternative 3.

Under this alternative rates would ensure repayment of all FCRPS costs and would include costs for carrying out provisions of the alternative such as conservation investment, acquisition of resource capability, and other authorized programs. Rates would continue to be confirmed and approved by the Federal Energy Regulatory Commission.

The rate impacts would vary somewhat from existing policy because residential, commercial, and industrial customers of investor-owned utilities would receive lower rates, while direct-service industrial customers would pay higher rates. However, preference customer rates should be lower than under the proposal since cost-effective conservation would be mandated and BPA purchase of resources in lieu of separately owned resources should result in lower plant financing costs.

With lower rates for customers of investor-owned utilities, the rate disparity between publicly owned and investor-owned utilities would be reduced, although not eliminated. To the extent that IOU customers had lower rates with this alternative and responded to the lower prices (price elasticity effects), they would be expected to increase their consumption levels. However, the aggressive conservation program under this alternative may offset the price effect of a lower rate. Expanded BPA authority under this alternative would be applied toward achieving all cost-effective conservation that would result if electricity was priced at the full incremental cost of new resources. Even though rates would be lower, this alternative would result in more total conservation than if BPA's authority were unchanged.

Direct-service industrial customers would pay higher rates under this alternative than under existing policy, but would be assured of a sufficient supply of power to operate their plants. However, because these customers have very low response to price increases or decreases, within the range of prices contemplated under this alternative, there would be almost no change in power consumption by direct-service industrial customers except for increased conservation.

(5) Alternative 4.

As in Alternative 3, rates would be set to include repayment obligations, conservation investment, acquisition of resource capability, and other authorized programs.

With this alternative, BPA would develop wholesale power rates for utilities in the Pacific Northwest. These rates would be based on a two-tier concept with a lower rate for public service, rural, domestic, and transportation systems, and higher rates for all other customer classes. This would produce different impacts than under the other alternatives.

All residential and rural customers in the Northwest would have lower electric bills relative to their bills under BPA's existing policy. Based on the expected response to lower rates, these customers would increase their consumption. However, with the strong conservation program included in the alternative, the price effect could be offset, and consumption levels of rural and domestic customers could remain near that under existing policy.

The rate to direct-service industrial customers would rise under this alternative. However, because this group does not respond readily to price changes, there would be very little impact on their consumption.

Without details on the cost of resources and the resulting rates, it is difficult to determine whether commercial and other industrial customers would pay more or less for power than under existing policy.

The disparity in rates between domestic and rural customers of preference customers and investor-owned utilities would be reduced, but not eliminated. Other factors, such as the costs of each utility's distribution system and percentage of requirements met with BPA power, would determine the magnitude of the reduction in disparity.

e. Direct-Service Industrial Customers.

As discussed in Chapter III, when existing DSI contracts expire, DSIs would have four options regarding Northwest operations: apply for service from utilities in or near whose service area the industries were located; make arrangements to purchase resources elsewhere and seek transmission services from the Federal system and/or regional utilities; construct their own generating resources, either individually or as a group; or cease operating in the region.

In the areas of economic and environmental impacts, the critical question is not so much who serves the industries, but whether or not they operate in the region. The impacts discussed in Section IV.A.2.e of this chapter would continue if the plants could be served.

If the firms were not able to obtain electric power in the amount or at a price that would allow continued economic operation in the region, the resulting impacts from plant shutdown would vary widely depending upon the local area in which the plant was located. Economically, the impact would be primarily dependent upon the importance of the plant and associated employment to the local economy. The DSI customers of BPA are an important and integral segment of the economies of Washington, Oregon, and western Montana. However, the specific importance of the customers to local economies varies substantially within the region. Plants sited in urbanized counties with diversified economies would have a significant but not critical impact. Workers unemployed by plant shutdown in these areas could be absorbed into the local work force, presumably reemployed at other neighboring industries. The duration of individual worker unemployment would depend upon local conditions at the time of plant shutdown and is impossible to predict at this time.

However, many of these plants are sited in rural communities where the facility is the main industrial activity. The DSI customer in this economic setting is often the principal component of employment and income, and frequently the main tax source for public services in the area. Closing such facilities would place a severe economic burden on these small communities.

In 7 of the 16 counties in which DSI plants are sited, these plants directly and indirectly represented between 19 and 50 percent of the total county economy in 1975. Impacts approaching 20 percent of all employment in a local area must be assumed to bear significantly on the local economic base. Also, communities with the most significant impact on the direct-service industries generally have populations of less than 50,000. If the plant workers were unemployed, they would likely leave the community to find comparable employment, therefore reducing area population and undermining the economic structure of the area. Spinoff impacts in the form of a decreasing tax base and underutilization of community facilities as population declined would be experienced. The region's DSIs currently supply one-third of the nation's primary aluminum, 9 percent of the nation's supply of primary nickel (the total national output), and from 10 to 15 percent of the requirements for crude silicone carbide abrasive. Closing the regional DSIs would have significant impacts on the nation's aluminum markets and prices, and silicone carbide markets. To rebuild the regional primary aluminum capacity in another area of the nation would require an investment in excess of three billion dollars at today's replacement costs.

Environmentally, the impacts of a DSI's decision to close down would be positive for the region. Air pollution loadings in any of the areas where plants were sited would be reduced, with the most significant impacts in those areas where the plants were major contributors to pollution in the local airshed and where air quality standards were being exceeded. However, in no instance would plant shutdown alone allow the achievement of national ambient air quality standards. The same would hold true in the areas of water quality, terrestrial environment, health effects, and impacts on endangered species. After a period of time of nonoperation, the local environment might return to pre-plant status, although other industry might have been developed in the area in the meantime.

Impacts on the power system are determined by who serves the DSIs. If the industries were not served through the Federal power system, i.e., from BPA or through preference customers, the services they provided (as discussed in Section IV.A.2.e.(3). of this chapter) would be lost to the total system, including operating reserves, forced outage reserves, and a safety margin against plant delays. If the power now committed to the direct-service industries were contracted through a utility or utilities, these services would have to be supplied through alternatives such as combustion turbines, a lower percentage of firm power being contracted, construction of more capacity units being constructed, or perhaps through alternative contracts for the quality of power currently provided to the DSIs.

If the DSIs provided their own power, either independently or through a group of utilities not dependent on the Federal system for this energy, these resources would be available to certain portions of the region. It is not possible to predict specific impacts from this arrangement due to the uncertainties in its formation, terms, etc.

As discussed in Section IV.A.2.e, BPA does not presently have a long term proposal for serving the direct service industries. This issue is part of the allocations policy currently under development. In the short term BPA will continue to operate under the IF-1 interim agreements until contract expiration.

Under the proposal and alternatives only Alternatives 3 and 4 specifically take a position on providing new service contracts to the industries. Under both of these alternatives the industries would continue to be served directly by BPA and would provide regional reserves as previously discussed.

4. Impacts on Power Transmission.

a. Transmission Planning.

(1) Impacts of the Proposal.

Several impacts on power transmission facilities would result from expansion of the "one-utility concept" of transmission planning. These impacts include avoiding duplication of transmission facilities, maximum use of existing and future transmission corridors, increased use of higher voltage, more efficient transmission systems, and development of interconnections between regions.

Coordination of the planning and construction of transmission facilities in the region results in fewer transmission lines. Multipurpose transmission facilities would be built based on the combined requirements of the utilities of the region. In this manner transmission facilities could be shared rather than duplicated. This type of coordination has been a large factor in the planning of the existing transmission system in the Pacific Northwest. As a result of this cooperative effort and its role in it, BPA has constructed and maintains approximately 80 percent of the bulk transmission capacity needed in the region. In the absence of coordination, the response would be to construct more single purpose and possibly redundant facilities which would result in increased environmental impacts.

When appropriate and in areas where right-of-way is restricted, BPA plans to remove existing low-voltage lines and use the right-of-way for higher voltage lines. BPA can, therefore, provide right-of-way for higher voltage lines by removing existing lower voltage lines. The use of existing right-of-way reduces the environmental impact of future transmission lines.

Further, when the total regional loads and resources are combined, high-voltage transmission facilities become economoically attractive. For example, BPA is evaluating advanced transmission technology, such as 1200-kV a-c transmission. An 1200-kV a-c transmission line has enough capacity to transmit up to 10,000 MW of power. Such high-voltage, high-capacity transmission lines not only conserve energy by reducing transmission line losses, but also conserve land by increasing the transmission capability of existing and new corridors.

Interregional coordination provides for the energy exchanges between regions. Exchanges may result from the availability of surplus energy and capacity or the diversity of loads between regions. Interconnections presently exist between the Pacific Northwest and the Pacific Southwest, as well as between the States of Montana, Idaho, and Utah. Interconnections also exist between the Pacific

Northwest and Canadian utilities in British Columbia. Future high-voltage interconnections would depend on need and justification and would be constructed to the extent there was cooperation between BPA and other utilities in the Pacific Northwest with utilities of other regions.

(2) Impacts of Alternative 1.

Under the reduced authority of this alternative, BPA would not be able to continue the transmission program offered under the proposal. This would have several impacts on power transmission by BPA and other utilities throughout the Pacific Northwest. These impacts could include duplication of transmission facilities, reduced use of existing rights-of-way, increased new corridor development, reduced use of higher voltage transmission systems, and fewer interconnections between regions.

Without regional coordination, more transmission lines would be constructed by the utilities of the region. Each utility would tend to construct facilities especially for its own needs without taking into consideration the needs of the total region. This could lead to the construction of duplicate lines.

The use of existing rights-of-way would be reduced because use of the FCRTS would be reduced.

Higher-voltage lines, such as 1200 kV, would not be practical under this alternative. The additions to the 500-kV grid would probably continue, and BPA would be less likely to develop a high-voltage system.

There would be fewer interregional ties, such as the proposed second d-c line, if BPA's authority were reduced. These interconnections would be limited by the willingness of the region's utilities to perform the coordination function BPA presently provides.

(3) Impacts of Alternative 2.

The impacts of this alternative would be similar to those of Alternative 1. BPA's role would be reduced and its coordinating functions performed by mutual operating agencies (MOAs). It would be more difficult for BPA to implement its policies of encouraging the use of existing right-of-way, developing a regional transmission system, and conserving energy through the reduction of transmission losses.

The one-utility concept would continue to the extent the MOAs adopted those policies in planning additions to the regional transmission system.

(4) Impacts of Alternative 3.

With new authority and an expanded role, BPA would become better equipped to expand the one-utility concept in transmission planning. It would be able to avoid duplication of transmission facilities, utilize existing and future transmission corridors to a greater extent, increase use of more efficient higher voltage transmission systems, as well as provide for interconnections between regions.

Implementation of a conservation program through new bonding authority would delay the need for generation and corresponding transmission development. It is anticipated that the development of small-scale cost-effective renewable resources would have only a small impact on the transmission program. However, the smaller size renewable resources would increase the need for additional distribution facilities and reduce the need for high-voltage transmission. Using small-scale or renewable resource generation to back up radial transmission to isolated areas would reduce the need for backup transmission to those areas.

(5) Impacts of Alternative 4.

Assuming the Regional Commission would fully implement the one-utility concept, it would direct BPA to develop transmission plans based on avoiding duplication of transmission facilities, using existing right-of-way, maximizing use of future transmission corridors, increasing use of higher voltage and more efficient transmission systems, and possibly increasing the development of interconnections between regions.

The Commission's policy of constructing cost-effective renewable energy resources could impact the transmission program through the development of small-scale generation in the load centers or the displacement of electrical energy through the use of alternate and renewable sources, such as solar and geothermal, which would tend to reduce the transmission and generation requirements of central station facilities. Again, the size (scale) and location of the nonconventional renewable resources will determine the impact to the bulk power transmission facilities.

b. Transmission Services.

(1) Impacts of The Proposal.

The transmission service rates have a minor impact on the transmission program. If BPA rates were lower than the cost to a utility of building its own facilities, then the transmission impact would be less. If the utility built its own facilities, the transmission impact would be greater. Lower transmission rates usually preclude the construction of transmission lines by non-Federal utilities.

The continued use of wheeling agreements would optimize the use of existing transmission facilities, avoid duplication of facilities, and help avoid or postpone the construction of new transmission facilities.

The continued use by BPA of transfer agreements to serve its customers would also reduce the need for building Federal lines.

(2) Impacts of Alternative 1.

Reduction of BPA's role would result in BPA providing less transmission services. The costs for other utilities to provide these services would continue to be higher. The service charge would increase at a slower rate than under the proposal. Thus, utilities which would obtain Federal transmission services would have lower transmission costs than those which would have to develop their own services.

With a reduced role, BPA would have less capacity available on its system for incidental wheeling. Thus, other utilities would have to provide for unanticipated transmission requirements. The amount of future wheeling agreements between BPA and others would be reduced in this alternative.

(3) Impacts of Alternative 2.

The MOAs would either construct their own transmission facilities or use BPA's existing system. In the long run, wheeling on BPA's system would be reduced. As BPA's existing system capacity became less available, the MOA's or other utilities would have to provide their own facilities. This would be at a greater cost than had BPA provided the service.

The overall transmission losses for the region would be greater due to the development of lower voltage, less efficient, single purpose transmission systems. BPA would continue to add facilities that were cost-effective facilities to reduce transmission losses.

BPA customers would continue to enter into use-of-facility service contracts. This type of service includes low-voltage distribution transmission to utility customers.

The use of excess capacity on BPA's system for incidental wheeling would be reduced. As the MOAs built their own facilities, they would have excess capacity for their own use.

(4) Impacts of Alternative 3.

Federal legislation to increase BPA's authority would allow BPA to expand the transmission services it presently offers to utilities. The transmission services provided would remove the need for utilities to build their own transmission facilities. To the extent this centralized approach to transmission planning and construction would minimize redundancies, the environmental impacts would be similarly reduced.

(5) Impacts of Alternative 4.

The Regional Commission would be likely to direct BPA to provide the same transmission services it provides now. The services BPA provided would avoid the need for other utilities to build their own facilities to transmit bulk power from their generators to their load centers.

BPA would be the Pacific Northwest's bulk power transmission utility. As in Alternative 3, this would optimize the use of existing transmission facilities, and prevent construction of duplicate transmission facilities.

E. Summary and Comparison of Impacts of the Proposal and Alternatives.

1. Proposal.

With regard to planning considerations and environmental impacts, the proposal represents an intermediate scenario in terms of both BPA's influence on regional planning and power system development and environmental impacts of the proposed action. This relationship is a direct result of the proposal's effect on: (1) the level of regional cooperation/coordination attained; (2) the probability of a load-resource balance; and (3) the extent to which nonpower interests would be considered and accommodated. The influence of the proposal on these three areas has a direct bearing upon the kind and degree of impacts that would result.

With regard to regional cooperation and coordination, the proposal provides for increased BPA involvement in that BPA would participate in preparation of a regional load forecast and annual planning document. The forecast would provide a state-of-the-art projection of regional loads and resources, and the planning document would discuss regional energy problems and potential solutions. Neither of these documents is currently prepared and both would be instrumental in alerting the region to power and non-power problems. Through this increased awareness, BPA, utilities, states, and others would be better prepared to respond in time to avoid a regional load-resource imbalance. BPA would initiate regional ccoperation where necessary, and not merely encourage cooperation as it has in the past. However, the proposal does not provide for a formal, regionwide institutional process which would assure that long-term problems would be satisfactorily resolved. Accordingly, load-resource imbalances are possible, although less likely than would be the case with Alternatives 1 and 2, and more likely than with Alternatives 3 and 4. This conclusion is reinforced by the fact that the proposal does not resolve the region's current difficulties in financing new resources, nor affect the long leadtimes and unexpected delays currently experienced in developing new resources.

Nonpower interests would be accommodated best via a formalized, stable, broad-based regional power planning process, preferably administered by a single agency/authority responsible for a comprehensive river management policy. Such an approach would routinely consider nonpower considerations along with competing power requirements. Because the proposal represents an improved regional planning process over that presently used, nonpower considerations would be better served than in the past when power generation took precedence over nonpower aspects of river regulation. However, by comparison with Alternatives 3 and 4, the proposal lacks mechanisms to assure the routine consideration of nonpower interests.

Under the proposal, the region's current emphasis on conventional thermal resources to meet future resource needs is likely to continue, although there will be an increase in the use of some forms of

TABLE IV-54

Effect of BPAs Proposal and Alternatives on Resource Development

RESOURCE / ALTERNATIVE	GENERAL	HYDRO	CONSERVATION	RENEWABLES	COAL	NUCLEAR
1	Reduced level of regional cooperation and coordination. Energy resources developed would tend to be small-scale (< 400 MW) due to technical and institutional limitations. Facilities would be dispersed throughout the region and load center development would be enhanced, due to increased transmission requirements and costs.	Increased incentives to preference customers for the development of additional Federal generation. Limited financing capability and restricted Federal construction of transmission would limit utility construction of major hydro facilities. Utilities would have added incentives for small-scale hydro development near load centers; desirability of remote sites would be decreased.	Organized conservation programs would be limited without regional institutional measures for program development. Increasing probability of resource emergency programs which depending on the severity of the problem in the local area could approach curtailment. Programs and their effectiveness would vary widely within the region and would fluctuate as the utilities' load/resource balance changed.	Proven technology such as biomass conversion, industrial cogeneration, and other combustion-based technologies would he encouraged due to their small size, lower risks, and ready availability. Application of new unproven technologies would suffer because without adequate additional resources available in the event a new resource does not perform as anticipated, utility managers are unlikely to take the risk.	Small-scale development would predominate due to limited capital availability, size of loads to be served, and shorter lead times. Proven technology would be preferred by utilities which, without a regional program, would be hesitant to undertake risks in resource planning and development. Large capital requirements, lack of regional financing provisions, and the lack of mechanisms to integrate transmission and resource services would preclude large-scale development by most of the region's utilities under this alternative.	As with coal, large-scale development would be restricted to IOUs or large preference customers in the region. Lack of public involvement opportunities would increase probability of delays in resource construction and licensing. Nuclear development would be most restricted under this alternative.
2 (BASELINE)	Reflects existing regional structure. Continuing high probability of load/resource imbalance. Higher degree of utility interaction than in Alt. 1 would improve regional resource financing capabilities though limitations would still exist restricting large generating projects. BPA would continue to provide integrating services and facilities.	Utilities would continue to explore remaining hydro potential. Increasing costs of alternate sources and projected long-term deficits may provide new incentives for sites currently not considered viable due to economic or environmental constraints. This would apply also to potential Federal sites proposed in the past.	Lack of a regional program would limit resource effectiveness. Major impact would come from utility and consumer reaction to potential shortages. Effects would vary throughout the region with a significant part of the reduction lasting only for the duration of each shortage.	Emphasis on proven technology (biomass, cogeneration, etc.). Lack of regional structure and resource backup would discourage utility risk taking. Utility interaction may provide for diversity tradeoffs. Preference customers could have some access to FCRPS for these services. IOUs probably would not.	Development would continue, particularly in small-scale plants as financing difficulties limit large-scale development for many of the region's utilities. Private utilities, particularly those with coal reserves, might rely heavily on this technology due to controversies surrounding other forms of central station generation.	Limited development possible through utility groups or MOAs. Financing and capital requirements continue to be a major hindrance without regional arrangements. Utility and industrial cooperation could permit coordinated planning to accommodate the large blocks of power produced as well as potentially providing for reserves and other integrating services alleviating some development hurdles.
PROPOSAL	Continuation of existing level of regional cooperation and coordination. Major change over regional status quo is BPA's increased role in and development of a regional conservation program. This would reduce the overall need for development of new regional resources and aid the region in balancing loads to resources. Lack of regional financing arrangements would continue to hinder all types of resource development.	Utilities would continue to pursue remaining hydro potential. Decreased regional resource needs and reduced likelihood of a load/resource imbalance would reduce regional pressure for developing sites which are economically or environmentally controversial.	Regional conservation program would be enhanced through expanded BPA activities promoting and coordinating conservation efforts. BPA RD&D projects would provide documentation of program effectiveness which would aid utilities in accepting and implementing the resource. As BPA and some public utilities would be unable to "purchase" or otherwise finance conservation measures funding would continue to be a problem. Public acceptance would he improved due to perceived program equity. Program success would also be enhanced by a planned approach to resource development as opposed to a reactive posture.	Emphasis on proven technology (biomass, cogeneration, etc.). Lack of regional structure and resource backup would discourage utility risk taking. Utility interaction may provide for diversity tradeoffs. Preference customers could have some access to FCRPS for these services. IOUs probably would not.	Development would continue, particularly in small-scale plants as financing difficulties limit large-scale development for many of the region's utilities. Private utilities, particularly those with coal reserves, might rely heavily on this technology due to controversies surrounding other forms of central station generation. Conservation reduced regional loads would reduce generation required to meet regional demands.	Limited development possible through utility groups or MOAs. Financing and capital requirements continue to be a major hindrance without regional arrangements. Utility and industrial cooperation could permit coordinated planning to accommodate the large blocks of power produced as well as potentially providing for reserves and other integrating services alleviating some development hurdles. Conservation reduced regional loads would reduce generation required to meet regional demands.

3	Provides a formal framework for regional interaction. New ability to use regional investment in the Federal system as equity in financing new resources. Utilities would continue to construct resources with BPA purchasing the output. Increased regional cooperation and coordination and centralized operations would decrease total amount of resources required due to maximized use of diversity tradeoffs, etc. Increased public involvement and formalized planning process would accommodate resource controversy, and potentially reduce construction lead times and cost. Reduced probability of load/resource imbalance. New financing arrangements would reduce costs of all resources.	Region would continue to pursue remaining potential. Increased opportunities for public involvement and reduced risk of resource deficits may allow nonpower and conservation interest to successfully oppose development of projects currently unacceptable due to environmental constraints.	Provide major requirements and incentives for conservation program development. Gives top priority in BPA's purchase of resources to cost-effective conservation. Regionwide incentives for both public and private utility customers. Formal regional planning would assure cognitive treatment of conservation resources in resource planning. Major impact on regional demand, particularly in meeting short-term deficits. All regional utilities and consumers would have access to technical expertise and program funding. Utility, local, State government implementation would increase public acceptance as measures could be tailored to the locale.	New authority for BPA to invest in renewable resources as a priority and to build renewables which may be unproven or too risky for utilities would provide major incentives for development. Proven technologies would continue to be exploited. Developing resources to accommodate total regional load would increase the system's flexibility in accommodating these potentially nonfirm resources.	Due to economics of scale and a desire to minimize ancillary facilities development would probably be large-scale at multiunit sites. Environmental constraints may result in plant siting away from major load centers. Reduced regional resource need and priority to alternative resources by cost-effectiveness may limit use of this option.	Due to economics of scale and a desire to minimize ancillary facilities development would probably be large-scale at multiunit sites. Environmental constraints may result in plant siting away from major load centers. Reduced regional resource need and priority to alternative resources by cost-effectiveness may limit use of this option. Conservation reduced regional loads would reduce generation required to meet regional demands.
4	Regional commission established to administer power system and assume full public utility responsibility including development and construction of resources. Two-tier/lifeline rate structure. Utility participation voluntary but major incentives would exist for participation. Shift of resource development responsibilities to a single source would increase likelihood of a single resource scenario occurring.	Region would continue to pursue remaining potential. Increased opportunities for public involvement and reduced risk of resource deficits may allow nonpower and conservation interest to successfully oppose development of projects currently unacceptable due to environmental constraints.	Commission would have authority but no obligation to impose conservation programs including mandatory measures. Potential impact would be limited by political sensitivity of commission members, reducing likelihood of comprehensive mandatory measures being adopted. Two-tier rate structure and division of regional resources into pools could encourage and provide incentives. Effectiveness would depend on elasticity of use, cost of other resources, population growth, etc.	New authority for BPA to invest in renewable resources as a priority and to build renewables which may be unproven or too risky for utilities would provide major incentives for development. Proven technologies would continue to be exploited. Developing resources to accommodate total regional load would increase the system's flexibility in accommodating these potentially nonfirm resources.	Due to economics of scale and a desire to minimize ancillary facilities development would probably be large-scale at multiunit sites. Environmental constraints may result in plant siting away from major load centers. Reduced regional resource need and priority to alternative resources by cost-effectiveness may limit use of this option.	Due to economics of scale and a desire to minimize ancillary facilities development would probably be large-scale at multiunit sites. Environmental constraints may result in plant siting away from major load centers. Reduced regional resource need and priority to alternative resources by cost-effectiveness may limit use of this option.

renewable resources and conservation. In addition to the coal and nuclear technologies presently represented in the regional resource mix, biomass, cogeneration and small scale hydro will also be used, although in limited quantities. This is the result of the utilities having adequate financing capability to support conventional thermal resources, coupled with a lack of regional programs promoting the development of and assuming some of the risk of renewable resources. Many utilities may decide the risks of deficits are too great if renewable resources are planned to depend on them. BPA, because of its limited role, would be unable to provide "back-up" resources to promote the use of renewable resources.

The main effect of the proposal on future resources would be through its conservation proposal, which would decrease loads and therefore decrease the need for additional resources. The proposal would result in some energy savings; however, because it is based upon limited existing authorities with no provision for rate or allocation incentives, the full potential for conservation to reduce the need for future resources would not be realized. Because rates would continue to be based upon existing cost recovery criteria and limited by BPA's role as a wholesaler, rates would not be expected to significantly offset the need for additional future generation.

The proposal represents a significant expansion over past conservation activities. Within the limits of its authority, BPA would offer technical, administrative, and financial assistance to its utility customers to carry out conservation programs. These programs would reduce loads and decrease impacts on air, land, water that would otherwise occur as a result of resource development and operation. The proposed conservation program would impact the regional economy through increases in employment and sales within the building and materials installation industries.

Because of its provisions for continued transmission, load factoring, and marketing services, the proposal is not expected to have an affect upon resources already developed or those currently under construction pursuant to the Hydro-Thermal Power Program (HTPP).

In terms of environmental impacts, the proposal will come closest to resource Scenario E, although the impacts will be reduced due to reduced resource requirements resulting from an increased regional conservation program. These impacts will include air quality degradation from the combustion of coal and bio-mass, increased radioactive wastes from nuclear plants, long-term commitments of both capital and land, and added demand on the region's water resources. The hydro developments will impact fisheries both through reduced spawning areas and impeded migration.

Aside from the effect of BPA's proposed conservation policy the specific provisions of BPA's proposed program will have little effect upon the region's future resource mix. As discussed in page IV-281 and following, even the continued provision of BPA services is expected to have little effect upon regional resource development and composition. Aside from BPA services, the main factors affecting future resource selection and composition are capital costs, total utility costs (including fuel costs and availability), existing utility resource mix, size and type of load to be served, construction leadtimes, resource reliability and utility preference. As mentioned above, the probability is that the regional resource composition associated with the proposal is likely to resemble Scenario E. However, this probability is more a result of the region's reaction to the BPA proposal than it is a direct result of the proposal itself.

In terms of resource operation, the proposal represents an extension of the existing hydro-thermal relationships with only minor modifications in load and load shaping expected as a result of conservation, load management, and end-use resource development. However, the DSIs could dramatically alter load shapes if they acquired their own resources or ceased operations in the region.

The proposal does not take a position regarding BPA service to DSIs after their present contracts expire. Neither does the proposal change the requirements of existing law under which BPA then must allocate the DSIs' power to preference customers. Allocation under existing law is highly likely to be settled by court action; thus, no allocation scheme advanced under existing authority is likely to reduce the planning uncertainty which accompanies allocation uncertainty.

As discussed in Chapter III, the industries have four options when their contracts expire: (1) they could apply for service from the region's utilities; (2) they could purchase power from outside the region, obtaining the necessary transmission from regional entities; (3) they could construct their own generation resources; and (4) they could cease their operations in the Pacific Northwest.

Environmentally, a DSI decision to cease operation would reduce impacts on the region. Air emissions impacts would be reduced, as would impacts on land use and water quality. Socioeconomic impacts, however, would be adverse. If the industries stayed in the region or if they acquired their own power, the regional impacts of generation would depend on the type of resources constructed to serve industrial loads, and how much of their load would provide interruptible reserves. If resources currently committed to DSI loads did not serve as reserves or did so only on a limited basis, then the region would have to aquire additional reserve capacity.

As with all the alternatives, the proposal does not change BPA's repayment obligations. The cost of the system would still have to be recovered and significant rate increases would continue to occur. Consumption would decline in response to increases in electricity rates. In addition to reducing overall consumption, rate increases would have their greatest economic impact on low income residential consumers (by reducing disposable income for other commodities) and the direct-service industries (by increasing costs and thus either increasing the price of product or reducing production due to shutdowns).

The proposal provides for the continued operation, planning, and construction of the Federal Columbia River Tranmission System as necessary to meet total regional transmission needs, both Federal and non-Federal.

Although some utilities could still decide to build their own transmission facilities, the overall effect of the proposal would be to lessen duplication of regional transmission facilities and to optimize the use of existing and future transmission corridors. To date, these policies have resulted in the Federal Columbia Transmission System providing 80 percent of the bulk power transmission in the Pacific Northwest.

Additionally, the proposal would provide for the transmission necessary to continue interregional transactions and coordination. This in turn provides for sale of power surplus to the needs of the Pacific Northwest and enables diversity-capacity exchanges with systems to the north and south.

2. Alternative 1.

Of the alternatives analyzed in this document, Alternative 1 would result in the lowest level of regional cooperation and coordination. A reduced role for BPA, restricting the agency to the marketing of Federal power over a limited high voltage grid, would leave a vacuum in the regional energy planning and development process, which under this alternative must be filled by utilities operating either independently or in small groups. It is assumed that mutual operating agencies would not be formed under this alternative, although this is a practical option which is covered under Alternative 2.

This alternative, while preserving local utility autonomy and planning for future resource needs, would complicate the operation of the regional power system. Due to the lack of a formal coordination process to integrate various segments of the system and the diversity of utilities' interests resulting from different operating and legal characteristics, individual utilities would cease operating as part of a larger system and begin to assume more independent roles. The major impact of independent utility operation would be a lack of political and institutional flexibility to respond to changes in the regional energy situation. Rather than working together toward a common goal which would benefit all parties involved, each agency or small group of agencies would be more likely to operate in its own best interest, which in the long run may not be in the best interests of the region as a whole. This piecemeal decision process would result in inefficient utilization of the regional power system. Lack of public involvement in the planning process also would preclude public input to regional decisions relating to electric energy. This would increase the probability of legislative and judicial conflicts which could delay future energy resource development of all types.

Load-resource imbalances would be probable for individual utilities as well as for the region as a whole. Utilities would be dependent upon their own load forecasts and resource development programs. Some utilities would overforecast and develop too many resources, while others would underforecast and develop too few. Due to its restricted regional transmission grid and utility interaction, this alternative would provide limited opportunities for these effects to balance. Therefore, while regional resources might be sufficient to balance with regional loads, difficulties in distribution between utilities could cause local surpluses or deficits, with their associated impacts. By the same token, due to the limitations of intertie capabilities with other regions, and a lack of marketing coordination, the region could be unable to utilize interregional transmission to mitigate impacts of a regional imbalance assuring resources would be available outside the region.

Alternative 1 offers little promise that management of the region's water resources would satisfactorily accommodate nonpower considerations, as it contains no provisions for broad-based regional participation in energy decisionmaking, and could place intense emphasis on use of water resources for power production.

Energy resources developed within this regional structure would tend to be small scale (less than 400 MW) thermal generation such as coal, industrial cogeneration, biomass, etc., due to technical and institutional problems which would result if larger resources were attempted under this alternative. These facilities would tend to be dispersed throughout the region, and would likely be located closer to load centers than the large central station generation facilities currently under construction. As the facilities would be more dispersed, so would the associated environmental impacts. Locations near load centers would have the effect that impacts of generation would more directly affect the consumers of the power than at present. Local impacts of generation would not be as severe as with large-scale plants.

Development of large-scale central station generation under this alternative would be restricted to the IOUs and large preference utilities in the region, acting either independently or in joint ventures. Large capital requirements, lack of regional financing provisions, and the lack of mechanisms to integrate transmission and resource services would preclude independent large-scale development by most of the region's utilities.

Development of conservation and end-use resources would also be limited. Due to lack of documentation on program effectiveness and adequate resource backup in the event programs did not perform at their anticipated level, the deficit risk involved in the development of these resources might be too great for a utility to accept. In addition, many regional utilities question whether they have authority to "loan credit" to consumers for end-use resources. These resources would undoubtedly be supported; however, they likely would not be adopted regionally as potential long-term firm power resources for planning purposes. The risk of load-resource imbalance could result in a major need for energy conservation, but under this alternative the region would be lacking in institutional mechanisms for achieving it.

It is not possible to predict specific impacts until a particular technology is chosen. However, because of the likely emphasis on small-scale coal and biomass development, the impacts would probably reflect those indicated in resource Scenario C and A. Most significant would be localized degradation of air quality increased costs related to pollution control, increased demand on frequently limited water supplies and land commitments in high cost areas. Impacts of transmission requirements would be reduced.

Development of small-scale hydro would result in adverse impacts on fisheries primarily through reduced spawning areas and interference with migrations.

In general, resource development might be hampered by load forecast controversies as well as by lack of public involvement in the planning process. The results of this uncertainty would be the lengthening of construction and program lead times due to such issues as the need for power from new resources, further increasing both the probability of energy deficits and the cost of resource development.

BPA would operate the FCRPS resources to maximize benefits to Federal customers, rather than to the region as a whole. From a regional perspective, this would result in less efficiency and the loss of the benefits associated with "one-utility" operations. One of the major advantages of the hydro system, i.e., its compatibility with both conventional thermal and renewable resource development, would not be fully utilized due to a lack of coordinated planning and operations.

Measures to mitigate the impacts of resource development would be implemented on a utility-by-utility basis and would vary according to the type of facility constructed. A major mitigating factor in resource development, i.e., maximum system efficiency, would not be present under this alternative.

Net environmental impacts associated with the regional transmission development would increase under this alternative. As smaller generating facilities closer to the load centers were constructed, there would be less demand for high-voltage transmission and more demand for shorter, but lower voltage lines. This would reduce the use of existing high-voltage rights-of-way as well as requiring more line capacity to carry the same amount of power. Lack of conservation programs and incentives could also encourage the development of generating resources requiring transmission. Lack of coordinated planning might result in duplication of facilities. Long-term impacts associated with this situation would be higher line losses and larger commitment of land and other resources for transmission facilities. Additionally, as more entities became involved in line development and operation, transmission reliability would be more difficult to maintain.

Interties and associated benefits would also be less available to the power system if BPA's role were reduced. The region would be less able to depend upon exchanges with the Southwest and would have to build additional generation, institute load management programs, or reduce the availability of Federal firm power to compensate. In addition, there would be a loss of potential revenues from the sale of secondary power outside the region; which could increase both rates for Federal power within the region and the potential for spillage.

By restricting sales of firm power to existing preference customers, this alternative would continue the regional geographic discrepancy in Federal power sales. Investor-owned utilities and new publicly owned utilities would be dependent upon their own resources to meet existing and future loads. This would continue the regional rate disparity, not only between public and private utilities, but also between different classes of public utilities. The probability of court action to test an administrative allocation of Federal power would continue to result in planning uncertainty for all regional utilities.

If DSIs were not served through the existing preference customers, these utilities would have adequate Federal power to meet load growth into the 1990's. If DSIs were served, the resources would suffice only until the early 1980's. The former would give the existing preference customers more time to plan for new resources and perhaps encourage the use of renewable fuels as the technology was developed. However, termination of service to the DSIs has significant implications for the power system. Loss of the industries' high load factor could make it difficult to meet minimum river flows during low demand periods without spilling water, since less efficient use of intertie capacity might reduce the sale of surplus power to the Southwest and power delivered to the Southwest under capacity-energy exchanges is often returned as energy during low demand periods. The region would also be required to develop additional resources to provide for forced outage, load growth, and other reserves.

In general, power rates would tend to be higher under this alternative compared to the proposal, due to the combined effects of reduced efficiency in the use of the existing power system, lack of mechanisms for conservation, and higher resource development costs.

Alternative 1 would provide for the least efficient use of the Federal Columbia River Power System. By operating the Federal system and the individual utility systems as independent entities, the region would lose the benefits obtained from operation under the one-utility concept. In addition, this lower level of regional cooperation and coordination would restrict the public's involvement in the regional energy planning process and increase the possibility of conflict among differing interest groups. All of these factors would contribute to an increase in the adverse environmental impacts of development and operation of the power system under this alternative.

3. Alternative 2.

Alternative 2 represents a no-action alternative with respect to BPA's role in the region. It differs from Alternative 1 in that mutual operating agencies (MOAs) could be formed by the public and private utilities and DSIs to undertake the planning and development of future resources and resource programs. If MOAs were formed, the region would experience a higher level of cooperation and coordination than under Alternative 1, but would still lack the use of the Federal power system as an integral part of a total regional power system; rather, the Federal system would tend to be oriented toward serving the needs of BPA's preference customers. BPA would cooperate as much as possible with the MOAs as long as the ability of the Federal system to serve its mandated preference customers was not compromised.

This alternative would give the region more flexibility than Alternative 1 in planning the power system's future structure, as well as added political and institutional responsiveness to cope with contingencies which might develop. Lack of an extensive public involvement process would still make it difficult to effectively resolve regional energy and resource issues on a regional basis.

A significant probability of a load-resource imbalance exists with this alternative, as with Alternative 1. Increased regional interaction would allow for a greater flexibility among the utilities for surplus power sales, etc. However, unless a coordinated resource development program were initiated, balancing loads with resources would be difficult. Alternative 2 would not provide a regional financing structure allowing for the use of Federal facilities as equity in the development of future resources; therefore, the utilities could face financing difficulties as they extended their financial resources into the future.

Alternative 2 would provide slight improvement over Alternative 1 in terms of prospects for accommodating nonpower concerns. The creation of MOAs for the development and operation of new generating resources, continuation of BPA's existing role in constructing and maintaining the Federal high-voltage transmission grid, and its more active role in planning and coordination would have the cumulative effects of increasing the region's overall level of coordination and improving its physical and institutional capabilities to address nonpower concerns.

Formation of MOAs would increase the resource options open to the region's utilities. With combined loads and resources, the development of large central station generation would be possible on a more extensive scale than under Alternative 1. The restrictions on this development, as noted above, would be the limited financing capabilities of utilities and MOAs. Because of these financing limitations and potential operating limitations of the MOAs, a significant percentage of the region's resource demands probably could be met through small-scale thermal generation. Both resource options have significant long-term environmental implications including land use, water consumption and quality, and air quality, as well as social and economic impacts. With larger facilities, these impacts would be more concentrated at local resource sites. In addition, with large-scale nuclear generation there is no approved plan for long-term storage of radioactive wastes and plant decommissioning. As BPA's transmission role would be the same as at present, integrating facilities would not present the problems to resource development identified in Alternative 1.

Conservation would not be a significant contributor to regional resources under this alternative, due to the lack of a coordinated regional program, although MOAs could act to purchase conservation savings from their participant utilities. Only a portion of regional resources would be available as insurance in the event conservation programs did not prove to be effective. The absence of backup to conservation programs would increase the risk involved with program development. As under Alternative 1, resource development might be hampered by load forecasting controversies and the lack of public involvement in the planning process, increasing the probability of energy deficits and the costs of resource development relative to the proposal. The increased likelihood of energy deficits would increase the need for energy conservation, but the mechanism for achieving it would be relatively lacking compared to the proposal, although through MOAs conservation would be more effectively achieved than under Alternative 2.

The impacts associated with this alternative relate to those discussed under resource Scenario E, a mix of coal and nuclear.

BPA would work with the MOAs to maximize regional interface on resource operation, as long as the power available to BPA customers would not be jeopardized. The result of this cooperation would be that, although the region's systems would be operated in a coordinated manner, the regional power system would still consist of individual systems and not parts of an integrated regional energy system. This would cost the region a portion of the benefits of the "one-utility concept," including some degrees of regional flexibility in accommodating nonpower concerns and utilizing regional diversities. Coordination of the hydro system with new thermal resources would be greater than under Alternative 1, but significantly less than could be achieved under the full program of cooperation in Alternatives 3 and 4.

BPA would cooperate with the region's MOAs in the construction of the region's transmission grid, making efficient the use of all facilities and reducing the possibility of facility duplication. Environmental impacts would be lessened by the use of higher voltage lines to integrate the new resources developed, and by regional wheeling and exchange agreements. Use of existing and joint rights-of-way would decrease the land commitments which otherwise would be required for transmission. Lack of a regional conservation program would, however, continue to encourage the development of generation requiring transmission, which would increase the associated impacts.

Existing interregional facilities and their benefits would continue under this alternative. Benefits such as diversity exchanges would continue to reduce the resources required by the region and increase regional revenues.

Regional conflicts over allocation of Federal power could possibly be lessened by Alternative 2. However, a substantial controversy and a high probability of a judicial resolution is likely for any administrative allocation under Alternatives 1 and 2 or the proposal. This uncertainty would hinder utilities' efforts to plan for future resources. Power would be allocated to new preference customers as it was available. This power could become available upon the expiration of the DSI contracts. This change in load types would have the same implications as discussed in Alternative 1 regarding load shape, although under this alternative adequate intertie capacity could be provided to sell the power outside the region during low demand periods, providing revenues to the region. Reserves provided by the DSIs would be lost if DSIs were not served and would have to be provided by other resources, probably combustion turbines or pumped storage impacts. Without these reserves, less firm power could be provided by the Federal system.

As with Alternative 1, but to a lesser degree, this alternative would result in higher rates than the proposal, due to inefficiencies in system operation and higher resource costs.

Regional cooperation and coordination would be increased over Alternative 1, but lack of some aspects of formal regional planning would continue to cost the region in system efficiency and flexibility, requiring the development of more resources at a higher cost. Regional load-resource imbalances would still be possible, although the political and institutional framework would be better able to deal with it. The regional resource mix would probably include both large-scale central station and small-scale electrical generation, but the region probably would not depend heavily on conservation and end-use resources.

4. <u>Alternative 3</u>.

Alternative 3 constitutes one of two alternatives presented in this document, which, if implemented, would substantially increase the level of regional cooperation and coordination, and thereby move the Pacific Northwest closer to a "one-utility" system.

Alternative 3 would increase the potential for the Pacific Northwest to achieve its electric energy goals and to balance these goals against other regional objectives, such as environmental quality. Plans and other decisions emerging from the centralized regional planning process under this alternative would likely have greater validity in the eyes of the region at large. Some degree of consensus is essential to overcome the obstacles facing the Pacific Northwest in resolving its energy problems. This process would not, however, alter the present structure of state authority over energy facility siting and utility rates.

Another important outcome of Alternative 3 would be greater assurance, compared to the proposal and Alternatives 1 and 2, that regional loads and resources would be in balance in the short and long run.

Under Alternative 3, the region would have the institutional apparatus to resolve competing demands on the Columbia River system. This prospect derives from: (1) creation of a formalized regional planning process; (2) broadly representative participation in the regional process; and (3) reduced probability of resource insufficiency. These provide, at least potentially, the necessary ingredients of decisionmaking authority, management perspective, and energy stability to resolve river basin issues.

This potential is no guarantee of an outcome that adequately accommodates nonpower water requirements. With an increasingly centralized and open planning process comes the ability to make decisions which, in the event of an electrical energy crisis, could sacrifice nonpower values. Centralization also establishes a political pressure point, which, in combination with broad regional representation, could result in divisiveness and indecision. The prospect is aggravated by the fact that nonpower interests themselves are not necessarily compatible. Alternative 3 provides not a guarantee, but an opportunity to achieve balance in river management objectives.

Alternative 3 identifies conservation as an energy resource, giving first priority to implementing regional conservation to the extent it is feasible and cost-effective, and gives BPA additional authority to make such investments. The availability of tax-exempt financing for resources would reduce the costs of new resource development, which would ultimately be reflected in retail rates to consumers. Alternative 3 also contains the directive for BPA to develop cost-effective and feasible renewable and alternative resources before investing in conventional baseload and load-factoring resources. Although the future mix of regional energy resources cannot be specified from these mandates because too little is known yet about the comparative costs of alternatives, it can be concluded that under Alternative 3 the region would be likely to pursue a wider range of energy resource combinations than under the proposal or the first two alternatives, probably with greater diversity in size of resources developed. Given that conservation and many of the renewable and alternative resources would be environmentally more attractive than conventional resources, the cumulative effect of the resource priorities in Alternative 3 would be to reduce overall environmental impacts of meeting or reducing the region's electrical demands.

The effects of a broader range of energy resources on system operations would be mixed. Conservation and peakload management would probably reduce river fluctuations associated with hydro peaking, to the benefit of many nonpower uses of the Columbia and Snake rivers. Baseload thermal resources would require hydro operations to shape generation to load. The effects of integrating alternative energy resources into the system are more difficult to predict because their patterns of output and backup requirements are not well known at this time. It is likely, however, given the intermittent output of some of these resources, that the hydro system would have to adapt to unpredictable changes in output from these resources. This could superimpose a new and random regulation on existing hydro operations, reducing system flexibility to respond to nonpower flow requirements. The development of renewable resources would aid in conserving nonrenewable fossil and nuclear fuels.

The mixture of resources which would be likely to develop under this alternative would include components of resource Scenarios A, B, and E. The priority given to conservation would support development described in Scenario B (although mandatory measures would not be used), followed by renewable resources as in Scenario A, and including conventional coal and nuclear resources only after feasible and cost-effective resources under Scenarios B and A were fully utilized. Impacts resulting from these developments would include air emissions due to the manufacture of conservation materials and combustion of both renewable and fossil fuels; land use for resources other than conservation and also for transmission of output; water consumption; and effects on fishery migration of hydro operations to support resources developed.

Under Alternative 3, BPA would retain its central role in constructing and maintaining the Federal high-voltage transmission grid. This reponsibility and capability would permit the agency to continue to make optimum use of existing and future transmission corridors and facilities, upgrade existing and build new higher voltage transmission systems, and provide for interregional connections as needed.

Construction of decentralized resources nearer to load centers would reduce high-voltage transmission requirements. Use of small-scale resources, electrical or nonelectrical, to back up radial transmission to small load centers would also reduce the need for redundant main grid transmission to these areas. Conservation, and especially peakload management, could delay the need for additional generation and corresponding transmission capacity. The net effect of these contingencies would be to reduce the cost of transmission and impacts associated with transmission corridors and high-voltage lines, and increase to a lesser extent the impacts of distribution facilities.

To the extent the region continued to pursue development of central generation and associated high-voltage transmission, the reverse would be true. The "one-utility" concept of transmission planning would minimize the number of corridors necessary to achieve interconnection. The types of impacts associated with high-voltage transmission would not be likely to change as line voltages increased, however. Most, if not all, new high-voltage lines would be constructed by BPA.

Given the lower risk of resource insufficiency or surplus under Alternative 3, the need for additional interregional connections to offset shortages or market excess thermal generation would be reduced. The potential for additional surplus hydropower available from the region would be unchanged because the DSIs would be given long-term contracts for the purchase of BPA nonfirm power. Therefore, no additional intertie capacity would be needed as an outlet for nonfirm power which would be available if DSIs were not served. On the other hand, to the extent that greater efficiency in the operation of regional resources and enhanced ability to take advantage of interregional diversities under Alternative 3 increased the incentive for seasonal exchanges or reserve pooling, some additional intertie capacity might be constructed, or existing facilities upgraded.

Continued provision of load factoring services, load growth reserves, and forced outage reserves by BPA under Alternative 3 would have three general effects on the system: (1) maintain the efficiencies gained through centralized system operations; (2) avoid the need for individual utilities to provide their own more expensive load factoring and reserve generation (e.g., combustion turbines); and (3) continue utilization of the Federal hydro system for these services. The third effect would have mixed impacts on other uses of the river, depending on the magnitude and timing of the regulations associated with these services, but in general would reduce system flexibility in accommodating nonpower water demands.

The higher probability of resource sufficiency under 3 would ensure reliability in meeting the general requirements of BPA's preference customers, the residential loads of investor-owned utilities, BPA's DSI customer loads, and all other regional demand for electricity. The broader allocation of inexpensive Federal hydro power under this alternative would also allow a wider distribution of FCRPS benefits in the region, especially to residential customers.

Alternative 3 would also provide for a more general distribution of FCRPS power costs among the region's ratepayers. The disparity in regional retail rates would be reduced. Rates would include costs of conservation and other resources, but the requirement that new resources be cost-effective would tend to minimize increases in overall rates. DSI rates would increase substantially, at first to provide revenue to finance conservation programs, and later to maintain BPA revenues not produced by sale of lower cost power to other regional consumers.

Continuation of DSI service would have three major consequences for the region. First, it would retain this source of reserves to assure service to preference customer loads; second, it would sustain current system load factors and nighttime minimum flows; and third, although no alteration in current system operations would occur, it could reduce system flexibility to accommodate nonpower needs, because the additional loads would increase requirements on the system to generate power. It is possible, however, that this alternative could provide interruptibility of DSI loads to accommodate nonpower requirements for river flows.

This alternative would facilitate cooperative planning, economical development, and efficient operation of the region power system, based on an open and centralized regional process. A diversity of resource developments, including conservation, would be encouraged, and environmental impacts and economic costs and benefits would tend to be more widely distributed, due to the widespread participation of regional interests in system planning.

5. Alternative 4.

This alternative would essentially mandate regional cooperation and coordination. The one-utility concept would be realized at the wholesale level, limited only by the extent to which utilities chose not to participate in the regional energy program. BPA would have full public utility responsibility and marketing role for all regional power resources through the Commission. This would facilitate maximum coordination of power generation and bulk transmission to achieve efficient operation while minimizing adverse environmental impacts.

A possible adverse impact of the Commission's centralized authority would be the loss of autonomy and local control among utilities which participate in the regional program. Regional decisionmaking would of necessity override some of the independence which utilities presently exercise. The Commission would be vulnerable to becoming a political pressure point because of its focal position in the regional system, which could either lead to concessions to politically powerful interests, or inaction in case of conflicts between interests. Presumably, the advantages of one-utility operation would outweigh the loss of autonomy. This possible loss could be mitigated in two ways: the utilities would have the option of not participating in the regional plan (however, it is doubtful that any utilities would choose to forego the advantages of participating); and the diverse avenues for input to decisionmaking would allow utilities as well as their consumers to express their individual concerns to the Commission and BPA.

Centralization of regional power planning authority would also provide for centralized efforts to mitigate adverse impacts. Mitigation could range from programs to protect or restore wildlife to pollution controls to financial assistance for low-income consumers impacted by higher rates.

Similarly to Alternative 3, cooperation would extend beyond the utility industry to include State governments, through their appointees to the Regional Energy Commission, and local governments, through the Local Government Advisory Committee, as well as the general public, which would have access to the Commission via the public hearings required before major decisions by the Commission. Furthemore, State and local authority over siting and utility rates would be retained, thus State and local governments and citizens would be brought into the decisionmaking process for the power system without any loss of their independent authority over concerns within their jurisdiction.

The probability of load-resource imbalances would be less than under the proposal and the Alternatives 1 and 2. BPA's authority to acquire power resources would serve to prevent deficits. The public utility responsibility to provide service at reasonable rates would militate against the high costs of overbuilding, and the broad participation in the planning process would help to ensure that the Commission balanced loads and resources. The greatest assurance of load-resource balance would derive from the legal mandate to the Commission use its authority and financial capabilities to balance loads with resources.

Nonpower considerations, that is, multiple use coordination of river operations, would be explicitly included in the planning process as a variable in the regional forecast. In addition, public hearings would be required on decisions regarding water use in the Columbia Basin, thus these nonpower considerations would be taken into account in the planning and operation of the regional system. The political sensitivity of the Commission could become an obstacle to accommodating nonpower interests, however.

Commission-approved purchase of resource output by BPA would provide a strong mechanism for development of regional power resources. Further, BPA's full public utility responsibility under this alternative would demand that this purchase authority be exercised to develop sufficient generating resources or load reduction resources to assure that energy supplies are sufficient to meet demand. The provisions in this alternative for broad participation in the planning process would promote a better consensus in resource selection and, thus, would aid in reducing delays in resource development.

Conservation would most likely be foremost among the resources developed and would probably be developed to a greater degree than under the Alternatives 1 and 2 and the proposal, due to the Commission's authority to institute mandatory conservation. It is also probable that some thermal generation would be developed. All available generating technologies, both large and small scale, would be thoroughly examined in the planning process so that alternative technologies, particularly those which utilize renewable resources, could be developed as much as it would be cost-effective and feasible to do so. Renewable resource development would conserve nonrenewable fuel sources. However, until the time when decisions have been made regarding additional resource development, the mix of conservation, renewable resource technologies, and other generating technologies cannot be predicted. Thus, assessment of net resource impacts among the various alternative resources is not possible at this time.

Conservation would permit more efficient use of existing power resources, thus reducing the impacts due to development and operation of resources which otherwise would be necessary, while increasing both adverse and beneficial impacts of the conservation measures themselves, such as employment, manufacture of materials, etc. Development of other resources would result in additional land use, emissions, and operational demands on the existing system, as well as employment and other economic effects of power resource development. All resource types, including conservation, would add to regional power costs, which would be reflected in rates.

Environmentally, Alternative 4 would best accommodate resource Scenario B. Major impacts would include air quality degradation near load centers due to combustion of wood and municipal wastes, and land disruption accompanying geothermal development. Reduced need for transmission facilities would reduce the impacts of transmission development on land-use, wildlife, scenic values and other environmental resources.

Although Alternative 4 contains the highest probability for the occurrence of a maximum conservation resource scenario, it also provides the highest probability of any extreme resource scenario occurring. This is due to the decisions and authorities regarding resource development being centralized in one body, i.e., the Regional Commission.

The need for resources would be determined through the regional planning process, which would require accurate forecasts of loads and resources and considerable review of proposed plans by the Commission and all interested regional participants. The capability for resource development would be greater than Alternatives 1 and 2 and the proposal, particularly for the conservation resource, due to the ease with which resources could be financed and integrated with the existing regional system. Financing for regional resources would be assured through BPA guaranteed purchase of resources approved by the Commission.

The operation of the existing system would be affected most by the influence of conservation on loads and resource requirements, by the possible accommodation of nonpower uses of the river, and by the need for reserves and backup generation to new resources. The considerable amounts of conservation which could be expected under this alternative would probably reduce the adverse impacts of existing system operations. Accommodation of nonpower uses of the river system would benefit other river users, but to the extent that limitations on hydro generation required additional generation of other types, some adverse impacts would result. The need for reserves and backup generation to new resources could place considerable demands on the regional generation and transmission system, thus impacts would tend to be adverse, both for the system itself and for the regional environment.

Transmission development under this alternative would tend to be highly centralized. BPA would continue to develop the regional high-voltage grid. One-utility operation would benefit from extensive interconnection, thus quantitatively less transmission probably would be developed under this alternative; moreover, this tendency would be reinforced by the degree of energy conservation achieved, the efficiency of system operation, and the avoidance of unnecessary redundancy due to one-utility operation as compared to lesser degrees of coordination under the other alternatives. Development of some resource types which are best suited to small-scale applications could result in a need for numerous small transmission lines to link these resources to the regional grid.

BPA would probably continue to develop higher capacity transmission lines, because of their greater efficiency and their apparently lesser environmental impact, especially in regard to land use for rights-of-way. The transmission system would increasingly be under BPA ownership, as virtually all new high-voltage lines would be constructed by BPA. As in Alternative 3, the need for interties would probably be reduced due to the greater likelihood of load-resource balance.

Allocation of low-cost Federal power would be dictated by the legislation which would institute this alternative. Although the statutory preference for public agencies would be retained, low-cost power would be supplied to domestic and rural consumers throughout the region, regardless of whether they were served by a public agency or an investor-owned utility. The rate disparity among regional utilities would thus be reduced. The net effect would be that the incentive for creation of new publicly owned utilities would be reduced, but not entirely eliminated. The allocation of lowest-cost power might reduce the incentives for conservation among its recipients, but the Commission's capabilities in mandating and financing conservation would probably offset this effect. The redistribution of the benefits of low-cost Federal power might change the net consumption of power by the region as a whole, but this effect cannot be predicted.

Rates for power sold would continue to recover BPA's repayment obligations, including the costs of conservation and any other resources BPA acquired. Lower rates would apply to publicly owned utilities, domestic and rural consumers, governmental agencies, and publicly owned transportation systems, while other customer classes would pay higher rates. As noted above, the recipients of low-cost power would tend to increase their consumption, but this tendency could be offset by conservation programs. The domestic and rural allocation of lowest-cost power would tend to reduce, but not eliminate, the rate disparities among domestic and rural consumers of different types of utilities, and therefore would also tend to reduce the incentive to form new publicly owned utilities.

This alternative would provide assured supplies to the direct-service industries. Thus, the reserves and the secondary power market provided by these industries would continue, as would their employment, economic contributions, and environmental impacts.

Alternative 4 would create a centralized regional energy authority with broad powers to develop conservation and generation. Centralization of authority would facilitate economies of production and reduction of adverse impacts, but regional utilities would lose some of their autonomy to centralized decisionmaking.

6. Non-NEPA Findings.

In addition to their responsibilities under NEPA Federal agencies have responsibilities for carrying out the provisions of other Federal environmental laws. This section is a discussion of (1) the requirements of those other laws; and (2) how the BPA proposal and alternatives meet those requirements.

a. The Coastal Zone Management Act (CZMA), 16 U.S.C. 1451 *et seq.*, requires that

> "Each federal agency conducting or supporting activities affecting the coastal zone shall conduct or support thos activites in a manner which is, to the maximum extent practicable, consistent with approved state management programs." 16 U.S.C. 1456(c)(1).

Department of Commerce regulations implement the procedural provisions of the CZMA. 15 CFR Part 930 (44 F.R. 37142, June 25, 1979). These regulations define an "activity" as "any functions performed by or on behalf of a Federal agency in the exercise of its statutory responsibilities." 15 CFR 930.31. BPA's proposal and alternatives are thus "activities" for purposes of the CZMA.

There must be a determination whether BPA's activities (the proposal and alternatives) "directly affect" the coastal zone. 15 CFR 930.30. If these activities directly affect the coastal zone, a "consistency determination" is required. 15 CFR 930.34(a). An activity directly affects the coastal zone if (1) the activity is listed in the approved State management program as likely to directly affect the coastal zone; or (2) the Federal agency otherwise finds that the activity will directly affect the coastal zone. 15 CFR 930.35.

In the BPA service area, two States have approved management programs: Washington and Oregon. The "Washington State Coastal Zone Management Program (WSCZMP)" lists seven types of Federal activities directly affecting the coastal zone. These generally are Federal assistance, Federal licenses, or Federal projects such as acquisition, use, or disposal of land and water resources. WSCZMP Draft Amendments and Refinements at page 19. No activities such as the BPA proposal and alterantives are listed. The "Oregon Coastal Management Program (OCMP)" also lists seven types of Federal activities directly affecting the coastal zone. These generally are proejcts such as land acquisition and use (especially construction) and projects directly affecting water resources. OCMP at page 43. No activities such as the BPA proposal and alternatives are listed. Thus, the BPA proposal and alternatives do not directly affect the coastal zone as a result of listing in the approved State management program.

Would BPA's proposal or alternatives directly affect the coastal zone of Washington or Oregon? The Department of Commerce regulations do not define "direct affect." This determination must be made case-by-case. 15 CFR 930.33. An activity can be said to directly affect the coastal zone if the activity would be affected by the terms of the approved State management programs.

The WSCZMP establishes the basic policy of coordinated coastal development. WSCZMP at 119. This is accomplished primarily through shoreline management, facility siting, Outer Continental Shelf activity regulation, and beach access regulation. WSCMP Draft Amendments and Refinements. The BPA proposal and alternatives are policy-oriented, not development-oriented, and are not affected by the WSCZMP because there is no identifiable direct effect on BPA's policies by the terms of the WSCZMP in regulating shorelines, facilities, OCS activities, and beach access. Thus, the BPA proposal and alternatives do not directly affect the coastal zone of Washington and a consistency determination is not required.

The OCMP establishes goals for various uses in the Oregon coastal zone. Eight uses are identified which are subject to the OCMP because of possible impact on coastal waters. These uses include navigation, energy production, agriculture, recreation, mining, and fish and wildlife production. OCMP at 16-21. Nineteen identified goals set standards for the management of these uses. OCMP at page 8. The goals of the OCMP in regulating these uses do not affect the BPA proposal and alternatives because BPA's proposal and alternatives are policies of cooperation in meeting energy needs in the Pacific Northwest, not projects within the uses identified the OCMP. Thus, the BPA proposal and alternatives do not directly affect the coastal zone of Oregon and a consistency determination is not needed.

b. <u>The Endangered Species Act (ESA)</u>, 16 U.S.C. 1531 <u>et seq</u>., requires that

> "Federal agencies shall, in consultation with the (Secretary of Interior), utilize their authorities in furtherance of the purposes of this Act by carrying out programs for the conservation of endangered species and threatened species . . . ." ESA Section 7(a).

BPA shall use its authorities in carrying out the purposes of the Endangered Species Act. The purposes of the ESA are

> "to provide a means whereby the ecosystems upon which endangered species and threatened species depend may be conserved . . ." ESA Section 2(b).

> "It is further declared to be the policy of Congress that all Federal departments and agencies shall seek to conserve endangered species and threatened species and shall utilize their authorities in furtherance of the purposes of this Act." ESA Section 2(c).

The ESA further requires that

> "Each federal agency shall . . . insure that any action authorized, funded, or carried out by such agency . . . does not jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined by the Secretary . . . to be critical . . . ." ESA Section 7(a).

In utilizing its authority to build, maintain, and operate the Federal Columbia River Transmission System, BPA furthers the purposes of the ESA by: (1) consulting with the Secretary of Interior (through the appopriate regional office of the Fish and Wildlife Service) prior to undertaking any action which may affect an endangered or threatened species or adversely modify a critical habitat; (2) undertaking studies on the biological impacts of the Transmission System (described elsewhere in this EIS); and (3) undertaking mitigation measures, such as avoiding areas designated as critical habitats.

The BPA proposal and alternatives should be understood to include these three measures designed to further the purposes of the ESA. Alternatives 1 and 2, with less regional cooperation and coordination, would be less effective in meeting the purposes of the ESA than Alternatives 3 and 4, with greater regional cooperation, because central planning in the latter alternatives will more easily avoid areas of critical habitat, provide easier consultation with the experts at FWS.

c. The National Historic Preservation Act (NHPA), 16 U.S.C. 470 *et seq*., requires that

> "The head of any federal agency having direct or indirect jurisdiction over a proposed Federal or federally assisted undertaking in any State . . . shall, prior to the approval of the expenditure of any Federal funds on the undertaking or prior to the issuance of any license, as the case may be, take into account the effect of the undertaking on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register (of Historic Places)." NHPA Section 106.

The BPA proposal and alternatives are proposed undertakings for the purpose of the NHPA. BPA is to take into account the effect of these proposed undertakings on National Register and eligible properties prior to approval of funds for the proposal or alternatives.

Because the BPA proposal and alternatives are at the plicy level, there will be no expenditure of funds having an effect on National Register and eligible properties resulting directly from a decision between the proposal and alternatives. Subsequent projects carrying out the policies in the proposal or alternatives may affect these properties and these effects will be taken into account when these subsequent projects are proposed.

It is a recurring facet of the BPA proposals and alternatives that Alternatives 1 and 2, because of less regional cooperation and coordination, would be less effective in meeting the purposes of environmental protection statutes than Alternatives 3 and 4, because these latter alternatives provide greater coordination among regional activities and greater central planning. The proposal represents an intermediate level of moderate central planning. The conclusion reached is that with greater cooperation and central planning, there is more opportunity to plan to avoid adverse effects on these protected elements of our human environment.

7. Environmentally Preferable Alternative.

As indicated in the overview, the proposal was developed because it is based on a known and readily available commodity--BPA's existing authority. However, Alternatives 3 and 4 are environmentally preferable to the proposal and the other alternatives. This conclusion is supported by the fact that these two alternatives would provide for a formal, comprehensive regional power planning process that would maximize efficiencies and assure that nonpower considerations would be routinely considered. Additionally, as a result of the regional decisionmaking processes embodied in these two alternatives, uncertainties regarding a regional load-resource balance would be minimized, as would be the necessity for reliance upon interregional transactions. Further, these planning processes would require that a greater emphasis be given to adopting a more diversified resource mix, including conservation and renewable or unconventional resources. If these resources were developed, there would be a decrease in the impacts associated with the development and operation of conventional thermal resources and the regional hydroelectric system.

By their improved planning processes, Alternatives 3 and 4, as well as the proposal, fulfill BPA's affirmative obligations toward preserving and enhancing the environment, as specified under the National Environmental Policy Act, the Coastal Zone Management Act, and the Endangered Species Act. The cooperation and coordination present in these processes leads to increased awareness of environmental needs and concerns which enhances the adoption of measures to protect these resources.

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LIST OF PREPARERS

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Pyrch, John B.
Senior Environmental Specialist (Geography)
For the past 4 years involved in evaluating environmental impacts of BPA's transmission proposals and marketing programs.
Educational background: B.S. - 1968 - Geography
M.S. - 1973 - Geography

Reams, Perry W.
Hydraulic Engineer
Twelve years of work experience with BPA as hydraulic engineer. Recently assigned to investigation & analysis of low-head hydro. Previously worked as electrical engineer with a PUD for 10 years.
Educational background: B.S. - 1957 - Electrical Engineering

Reinhart, Roy E.
Engineer
Several years of work experience in analysis of energy conservation alternatives including small wind energy conversion.
Educational background: B.S. - 1971 - Electrical Engineering

Seiffert, Randy D.
Environmental Specialist (Air Quality)
With Bonneville for 3 years evaluating environmental impacts, primarily to air quality, of power marketing proposals. Four years of previous employment with Environmental Protection Agency, Office of Air Quality Planning & Standards.
Educational background: B.S. - 1971 - Chemical Engineering

Simson, Gerry
Writer/Editor
Educational background: B.A. - 1968 - Biology
M.A. - 1972 - Anthropology

Spigal, Harvard P.
Public Utilities Specialist
Has worked with BPA for past five years. Initially in contracts section; last 3 years as Asst. to Power Manager directly involved in BPA power marketing policy formulation and review.
Educational background: B.A. - 1970 - History
J.D. - 1973

Taves, John
Sociologist
Three years of work experience with BPA. Primarily involved in evaluating social impacts of BPA's marketing and ratemaking policies & proposals.
Educational background: B.A. - 1968 - Psychology
M.S - 1971 - Social Psychology
Ph.D.- 1975 - Sociology

Willis, Lynda
Environmental Specialist (Industrial Engineering)
For the past 6 years has worked in the area of industrial pollution control and evaluations of power marketing policies to direct service industries.

Educational background:	B.S. - 1973 -	Environmental Sciences Urban Planning
	M.S. - 1973 -	Mechanical Engineering Air Pollution Control

Wolfe, Donald V.
Environmental Specialist
For past 3 years has been involved in evaluating and documenting ongoing environmental evaluations relating exclusively to the Role EIS.

Educational background: B.A. - 1973 - Psychology
Post baccalaureate study in economics, resource policy.

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(* Designates receipt of letter on Revised Draft EIS)

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United States Senate
Washington, D.C. 20515

C-3
Honorable Don Bonker
House of Representatives
Washington, D.C. 20515

C-4
Honorable Frank M. Church
United States Senate
Washington, D.C. 20510

C-5
Honorable Norman Dicks
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Washington, D.C. 20515

C-6
Honorable Robert B. Duncan
House of Representatives
Washington, D.C. 20515

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Honorable Thomas S. Foley
House of Representatives
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Honorable George Hansen
House of Representatives
Washington, D.C. 20515

C-9
Honorable Mark O. Hatfield
United States Senate
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Honorable Henry M. Jackson
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C-11
Honorable Mike Lowry
House of Representatives
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Honorable Warren G. Magnuson
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C-13
Honorable Ronald Marlenee
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Honorable Robert W. Packwood
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Honorable Joel Pritchard
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Honorable Allen Swift
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Honorable Steven D. Symms
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C-22
Honorable James Weaver
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Moscow, ID 83843

POCATELLO

IDAHO STATE UNIVERSITY LIBRARY
Pocatello, ID 83209

POCATELLO PUBLIC LIBRARY
812 E. Clark Street
Pocatello, ID 83201

PORTNEUF DISTRICT LIBRARY
5210 Stuart
Pocatello, ID 83201

REXBURG

RICKS COLLEGE
David O. McKay Learning Resources Center
Rexburg, ID 83440

SAINT MARIES

ST. MARIES PUBLIC LIBRARY
822 College
St. Maries, ID 83861

SANDPOINT

SANDPOINT-EAST BONNER COUNTY FREE
PUBLIC LIBRARY DISTRICT
SandpointBonner County Library
District
419 N. Second Avenue
Sandpoint, ID 83864

TWIN FALLS

COLLEGE OF SOUTHERN IDAHO LIBRARY
315 Falls Avenue
Twin Falls, ID 83301

MAGIC VALLEY LIBRARY SYSTEM
Idaho Library Region IV
434 Second Street, E.
Twin Falls, ID 83301

TWIN FALLS PUBLIC LIBRARY
434 Second Street, E.
Twin Falls, ID 83301

MONTANA

BILLINGS

BILLINGS PUBLIC LIBRARY
510 N. Broadway
Billings, MT 59101

PAUL M. ADAMS MEMORIAL LIBRARY
Rocky Mountain College
Billings, MT 59102

EASTERN MONTANA COLLEGE LIBRARY
1500 N. 30th
Billings, MT 59101

BOZEMAN

MONTANA STATE UNIVERSITY LIBRARY
Documents Library
Bozeman, MT 59715

BUTTE

MONTANA COLLEGE OF MINERAL SCIENCE & TECHNOLOGY LIBRARY
W. Park Street
Butte, MT 59701

DILLON

WESTERN MONTANA COLLEGE
Lucy Carson Memorial Library
Dillon, MT 59725

GLENDIVE

DAWSON COMMUNITY COLLEGE LIBRARY
P.O. Box 421
Glendive, MT 59330

GREAT FALLS

COLLEGE OF GREAT FALLS LIBRARY
1301 - 20th Street, South
Great Falls, MT 59401

HAVRE

NORTHERN MONTANA COLLEGE LIBRARY
Northern Montana College
Havre, MT 59501

HELENA

CARROLL COLLEGE LIBRARY
Carroll College
Helena, MT 59601

MONTANA HISTORICAL SOCIETY LIBRARY
225 N. Roberts Street
Helena, MT 59601

MONTANA STATE LIBRARY
930 E. Lyndale Avenue
Helena, MT 59601

KALISPELL

FLATHEAD COUNTY FREE LIBRARY
37 First Street West
Kalispell, MT 59901

LIBBY

NORTHWEST FEDERATION OF LIBRARIES
c/o Lincoln County Free Library
220 W. Sixth Street
Libby, MT 59923

MILES CITY

MILES CITY COMMUNITY COLLEGE
Miles City, MT 59301

MISSOULA

MISSOULA PUBLIC & MISSOULA COUNTY FREE LIBRARY
Pattee Street
Missoula, MT 59801

UNIVERSITY OF MONTANA LIBRARY
Documents Division
Missoula, MT 59801

UNIVERSITY OF MONTANA
ENVIRONMENTAL LIBRARY
758 Eddy Street
Missoula, MT 59801

OREGON

ALBANY

LINN-BENTON COMMUNITY COLLEGE
Learning Resource Center
6500 SW. Pacific Blvd.
Albany, OR 97321

ASHLAND

SOUTHERN OREGON STATE COLLEGE LIBRARY
1250 Siskiyou Blvd.
Ashland, OR 97520

ASTORIA

CLATSOP COMMUNITY COLLEGE LIBRARY
1680 Lexington
Astoria, OR 97130

BAKER

BAKER COUNTY PUBLIC LIBRARY
2400 Resort Street
Baker, OR 97814

BEND

CENTRAL OREGON COMMUNITY COLLEGE LIBRARY
NW. College Way
Bend, OR 97701

COOS BAY

COOS BAY PUBLIC LIBRARY
525 W. Anderson Street
Coos Bay, OR 97420

SOUTHWESTERN OREGON COMMUNITY COLLEGE
Learning Resource Center
Coos Bay, OR 97420

CORVALLIS

CORVALLIS PUBLIC LIBRARY
Corvallis-Benton County Library
645 NW. Monroe Avenue
Corvallis, OR 97330

ENVIRONMENTAL PROTECTION AGENCY
Corvallis Environmental Research Laboratory Library
200 SW. 35th Street
Corvallis, OR 97330

OREGON STATE UNIVERSITY
William Jasper Kerr Library
Corvallis, OR 97331

EUGENE

EUGENE PUBLIC LIBRARY
100 W. 13th Avenue
Eugene, OR 97401

LANE COMMUNITY COLLEGE LIBRARY
4000 E. 30th Avenue
Eugene, OR 97405

UNIVERSITY OF OREGON LIBRARY
Eugene, OR 97403

FOREST GROVE

PACIFIC UNIVERSITY
Harvey W. Scott Memorial Library
Forest Grove, OR 97116

GRANTS PASS

ROGUE COMMUNITY COLLEGE LIBRARY
3345 Redwood Hwy
Grants Pass, OR 97526

GRESHAM

MOUNT HOOD COMMUNITY COLLEGE LIBRARY
26000 SE. Stark
Gresham, OR 97030

HERMISTON

HERMISTON PUBLIC LIBRARY
213 E. Gladys
Hermiston, OR 97838

KLAMATH FALLS

KLAMATH COUNTY LIBRARY
126 S. Third Street
Klamath Falls, OR 97601

OREGON INSTITUTE OF TECHNOLOGY LIBRARY
Oretech Branch Post Office
Klamath Falls, OR 97601

LA GRANDE

EASTERN OREGON STATE COLLEGE
Walter M. Pierce Library
La Grande, OR 97850

LAKE OSWEGO

LAKE OSWEGO PUBLIC LIBRARY
706 SW. Seventh
Lake Oswego, OR 97034

MARYLHURST

MARYLHURST COLLEGE
Shoen Library
P.O. Box 11
Marylhurst, OR 97036

McMINNVILLE

LINFIELD COLLEGE
Northup Library
McMinnville, OR 97128

MONMOUTH

OREGON COLLEGE OF EDUCATION LIBRARY
345 Monmouth Avenue
Monmouth, OR 97361

NEWBERG

GEORGE FOX COLLEGE
Shambaugh Library
Newberg, OR 97132

ONTARIO

TREASURE VALLEY COMMUNITY COLLEGE
650 College Blvd.
Ontario, OR 97914

OREGON CITY

CLACKAMAS COMMUNITY COLLEGE
Marshall N. Dana Memorial Library
19600 S. Molalla Avenue
Oregon City, OR 97045

CLACKAMAS COUNTY LIBRARY
999 Library Court
Oregon City, OR 97045

PENDLETON

BLUE MOUNTAIN COMMUNITY COLLEGE LIBRARY
2410 NW. Carden
P.O. Box 100
Pendleton, OR 97801

UMATILLA COUNTY LIBRARY
214 N. Main Street
Pendleton, OR 97801

PORTLAND

LEWIS & CLARK COLLEGE
Aubrey R. Watzek Library
0615 SW. Palatine Hill Road
Portland, OR 97219

NORTHWESTERN SCHOOL OF LAW
Paul L. Boley Law Library
10015 SW. Terwilliger Blvd.
Portland, OR 97219

LIBRARY ASSOCIATION OF PORTLAND (9)
Multnomah County Library
801 SW. Tenth Avenue
Portland, OR 97205

PORTLAND COMMUNITY COLLEGE
Media Center
12000 SW. 49th Avenue
Portland, OR 97219

PORTLAND STATE UNIVERSITY
Branford Price Millar Library
934 SW. Harrison
P.O. Box 1151
Portland, OR 97207

REED COLLEGE
E. V. Hauser Memorial Library
3203 SE. Woodstock
Portland, OR 97202

UNIVERSITY OF PORTLAND
Wilson W. Clark Memorial Library
5000 N. Willamette Blvd.
Portland, OR 97203

ROSEBURG

UMPQUA COMMUNITY COLLEGE LIBRARY
P.O. Box 967
Roseburg, OR 97470

SALEM

CHEMEKETA COMMUNITY COLLEGE LIBRARY
4000 Lancaster Drive, NE.
P.O. Box 1007
Salem, OR 97308

OREGON STATE LIBRARY
State Library Building
Summer & Court Streets
Salem, OR 97310

OREGON SUPREME COURT LIBRARY
Salem, OR 97310

SALEM PUBLIC LIBRARY
585 Liberty Street, SE.
Salem, OR 97301

WILLAMETTE UNIVERSITY LIBRARY
900 State Street
Salem, OR 97301

SPRINGFIELD

SPRINGFIELD PUBLIC LIBRARY
320 North A Street
Springfield, OR 97477

THE DALLES

THE DALLES CITY-WASCO COUNTY LIBRARY
722 Court Street
The Dalles, OR 97058

TILLAMOOK

TILLAMOOK COUNTY PUBLIC LIBRARY
210 Ivy Avenue
Tillamook, OR 97141

WASHINGTON

ABERDEEN

GRAYS HARBOR COLLEGE LIBRARY
College Heights
Aberdeen, WA 98520

AUBURN

GREEN RIVER COMMUNITY COLLEGE
Holman Library
12401 SE. 320th Street
Auburn, WA 98002

BELLEVUE

BELLEVUE COMMUNITY COLLEGE
Library Media Center
3000 145th Place, SE.
Bellevue, WA 98007

PUGET SOUND POWER & LIGHT COMPANY
The Library
Puget Sound Building
Bellevue, WA 98009

BELLINGHAM

WESTERN WASHINGTON STATE COLLEGE
Mable Zoe Wilson Library
Bellingham, WA 98225

WHATCOM COMMUNITY COLLEGE
Learning Resources Center
5217 Northwest Road
Bellingham, WA 98225

BREMERTON

OLYMPIC COLLEGE
Learning Resources Center
16th & Chester
Bremerton, WA 98310

CENTRALIA

CENTRALIA COLLEGE LIBRARY
P.O. Box 639
Centralia, WA 98531

CHENEY

EASTERN WASHINGTON STATE COLLEGE
John F. Kennedy Memorial Library
Cheney, WA 99004

COLLEGE PLACE

WALLA WALLA COLLEGE
Peterson Memorial Library
College Place, WA 99324

ELLENSBURG

CENTRAL WASHINGTON STATE COLLEGE LIBRARY
Ellensburg, WA 98926

EVERETT

EVERETT COMMUNITY COLLEGE
Library Media Center
801 Wetmore
Everett, WA 98201

EVERETT PUBLIC LIBRARY
2702 Hoyt Avenue
Everett, WA 98201

LONGVIEW

LONGVIEW PUBLIC LIBRARY
1600 Louisiana Street
Longview, WA 98632

LOWER COLUMBIA COLLEGE
Learning Resource Center
1600 Maple
Longview, WA 98632

LYNNWOOD

EDMONDS COMMUNITY COLLEGE LIBRARY
20000 68th Avenue, W.
Lynnwood, WA 98036

MIDWAY

HIGHLINE COMMUNITY COLLEGE LIBRARY
Midway, WA 98031

MOSES LAKE

BIG BEND COMMUNITY COLLEGE LIBRARY
Bolling & 28th
Moses Lake, WA 98837

MOUNT VERNON

SKAGIT VALLEY COLLEGE
Library Media Center
2405 College Way
Mount Vernon, WA 98273

OLYMPIA

EVERGREEN STATE COLLEGE
Daniel J. Evans Library
Olympia, WA 98505

ST. MARTIN'S COLLEGE LIBRARY
Olympia, WA 98593

WASHINGTON STATE LIBRARY
Olympia, WA 98504

PASCO

COLUMBIA BASIN COLLEGE
Instructional Resource Center
2600 N. 20th Avenue
Pasco, WA 99301

PORT ANGELES

NORTH OLYMPIA LIBRARY SYSTEM
Library Service Center
2210 S. Peabody
Port Angeles, WA 98362

PENINSULA COMMUNITY COLLEGE
John D. Glann Library
1502 E. Lauridsen Blvd.
Port Angeles, WA 98362

PORT ANGELES PUBLIC LIBRARY
207 S. Lincoln Street
Port Angeles, WA 98362

PULLMAN

WASHINGTON STATE UNIVERSITY LIBRARY
Pullman, WA 99163

RICHLAND

RICHLAND PUBLIC LIBRARY
Swift & Northgate
Richland, WA 99352

SEATTLE

GOVERNMENTAL RESEARCH ASSISTANCE LIBRARY
Seattle Public Library
Attn: Jeanette Voiland
307 Municipal Building
Seattle, WA 98104

KING COUNTY LIBRARY SYSTEM (6)
300 Eighth North
Seattle, WA 98109

NORTH SEATTLE COMMUNITY COLLEGE
Instructional Resources Center
9600 College Way N.
Seattle, WA 98103

NORTHWEST FEDERAL REGIONAL COUNCIL LIBRARY
Arcade Plaza Building
1321 Second Avenue
Seattle, WA 98101

SEATTLE CENTRAL COMMUNITY COLLEGE
Instructional Resource Services
1705 Broadway
Seattle, WA 98122

SHOREWOOD HIGH SCHOOL
Ms. LoAnne Larson, Librarian
17300 Fremont Avenue North
Seattle, WA 98133

SEATTLE PACIFIC COLLEGE
Weter Memorial Library
3307 Third Avenue, W.
Seattle, WA 98119

SEATTLE PUBLIC LIBRARY (9)
1000 Fourth Avenue
Seattle, WA 98104

SEATTLE UNIVERSITY
A. A. Lemieux Library
Seattle, WA 98122

SHORELINE COMMUNITY COLLEGE
Library/Media Center
16101 Greenwood Avenue, N.
Seattle, WA 98133

SOUTH SEATTLE COMMUNITY COLLEGE
Instructional Resources Center
Seattle, WA 98106

UNIVERSITY OF WASHINGTON LIBRARIES
Suzzallo Library FM-25
Seattle, WA 98195

UNIVERSITY OF WASHINGTON
Engineering Library
Engineering Library Building FH-15
Seattle, WA 98195

UNIVERSITY OF WASHINGTON
School of Law Library
1100 NE. Campus Parkway JB-20
Seattle, WA 98195

SPOKANE

FT. WRIGHT COLLEGE OF THE HOLY NAMES LIBRARY
W. 4000 Randolph Road
Spokane, WA 99204

GONZAGA UNIVERSITY *
Crosby Library
E. 502 Boone Avenue
Spokane, WA 99258

SPOKANE COMMUNITY COLLEGE
East Mission Campus Library
3403 Mission
Spokane, WA 99202

SPOKANE COUNTY LIBRARY (5)
East 11811 First Avenue
Spokane, WA 99206

SPOKANE FALLS COMMUNITY COLLEGE
Library Media Services
W. 3410 Ft. Wright Drive
Spokane, WA 99204

SPOKANE PUBLIC LIBRARY (5)
Comstock Building Library
West 906 Main Avenue
Spokane, WA 99201

WHITWORTH COLLEGE
Harriet Cheney Cowles Memorial Library
Spokane, WA 99251

TACOMA

PACIFIC LUTHERAN UNIVERSITY
Robert A. L. Mortvedt Library
S. 121st Street & Park Avenue S.
Tacoma, WA 98447

TACOMA COMMUNITY COLLEGE
Pearl A. Wanamaker Library & Instructional Resource Center
5900 S. 12th Street
Tacoma, WA 98465

UNIVERSITY OF PUGET SOUND
Collins Memorial Library
1500 N. Warner
Tacoma, WA 98416

VANCOUVER

CLARK COLLEGE LIBRARY
1800 E. McLoughlin Blvd.
Vancouver, WA 98663

FORT VANCOUVER REGIONAL LIBRARY
Attn: Reference Librarian
1007 E. Mill Plain Blvd.
Vancouver, WA 98663

WALLA WALLA

WALLA WALLA COMMUNITY COLLEGE
LIBRARY
500 Tausick Way
Walla Walla, WA 99362

WALLA WALLA PUBLIC LIBRARY
238 E. Alder
Walla Walla, WA 99362

WHITMAN COLLEGE
Penrose Memorial Library
345 Boyer
Walla Walla, WA 99362

WENATCHEE

WENATCHEE VALLEY COLLEGE
Library Media Center
1300 Fifth Street
Wenatchee, WA 98801

YAKIMA

YAKIMA VALLEY COMMUNITY COLLEGE
Raymond Library Media Center
16th Avenue at Nob Hill Blvd.
Yakima, WA 98902

WYOMING

CASPER

CASPER COLLEGE LIBRARY
125 College Drive
Casper, WY 82601

CHEYENNE

LARAMIE COUNTY COMMUNITY COLLEGE LIBRARY
1400 E. College Drive
Cheyenne, WY 82001

LARAMIE COUNTY LIBRARY SYSTEM
2800 Central Avenue
Cheyenne, WY 82001

WYOMING DEPARTMENT OF ECONOMIC PLANNING AND DEVELOPMENT LIBRARY
Cheyenne, WY 82002

WYOMING STATE LIBRARY
Supreme Court & Library Building
Cheyenne, WY 82002

JACKSON

TETON COUNTY LIBRARY
King and South Streets
Jackson, WY 83001

LARAMIE

ALBANY COUNTY PUBLIC LIBRARY
405 Grand Avenue
Laramie, WY 82070

UNIVERSITY OF WYOMING,
WILLIAM ROBERTSON COE LIBRARY
P.O. Box 3334
Laramie, WY 82071

POWELL

NORTHWEST COMMUNITY COLLEGE LIBRARY
Powell, WY 82435

RIVERTON

CENTRAL WYOMING COLLEGE LIBRARY
Riverton, WY 82501

ROCK SPRINGS

WESTERN WYOMING COLLEGE LIBRARY
2500 College Drive
P.O. Box 428
Rock Springs, WY 82901

SHERIDAN

SHERIDAN COLLEGE, MARY BROWN KOOI LIBRARY
Sheridan, WY 82801

SHERIDAN COUNTY
FULMER PUBLIC LIBRARY
Loucks & Alger Streets
P.O. Box 1039
Sheridan, WY 82801

TORRINGTON

EASTERN WYOMING COLLEGE LIBRARY 3200
West C
Torrington, WY 82240

MEDIA

Associated Press
Attn: Steve Graham
1320 SW. Broadway
Portland, OR 97201

East Oregonian
Attn: Mr. Rick Larson
P.O. Box 149
Hermiston, OR 97838

The Hermiston Herald
Mr. Al Donnelly
P.O. Box 46
Hermiston, OR 97838

The Idaho Statesman
Mr. Jim Boyd,
Editorial Page Editor
P.O. Box 40
Boise, ID 83707

KINK Radio
Mr. Rich Hillman
1500 SW. Jefferson
Portland, OR 97201

KOHU - Hermiston
Mr. Ken Osuna
P.O. Box 145
Hermiston, OR 97838

The Missoulian
Mr. Don Schwennesen
P.O. Box 8029
Missoula, MT 59807

The Oregon Daily Emerald
Mr. E. G. White-Swift
P.O. Box 3159
Eugene, OR 97403

The Oregon Journal
Mr. Jerry Tippens,
Editorial Editor
1320 SW. Broadway
Portland, OR 97201

The Oregonian
Mr. Malcolm Bauer,
Managing Editor
1320 SW. Broadway
Portland, OR 97201

The Pendleton East Oregonian
Mr. John Snell
P.O. Box 149
Hermiston, OR 97838

Post Register
Attn: Mr. Dick Manning
P.O. Box 1800
Idaho Falls, ID 83401

The Seattle Post-Intelligencer
Mr. John DeYoung
Sixth Avenue & Wall Street
Seattle, WA 98121

The Seattle Times
Mr. Herb Robinson, Editorial
Page Editor
P.O. Box 70
Seattle, WA 98111

The Spokane Daily Chronicle
Mr. Gordon Coe, Managing Editor
P.O. Box 18
Spokane, WA 99210

The Spokesman-Review
Mr. Jim Bracken, Managing Editor
W. 927 Riverside
Spokane, WA 99253

The Statesman Journal
Regional Desk
P.O. Box 13009
Salem, OR 97309

The Tri-City Herald
Mr. Jack Briggs, Acting Editor
P.O. Box 2608
Pasco, WA 99302

The Weekly
Mr. Jim Lalolande
85 S. Washington Street
Seattle, WA 98104

Willamette Week
Mr. Richard Meeker
320 SW. Stark
Portland, OR 97204

REGIONAL CLEARINGHOUSES AND COUNTIES

Mr. Bruce Thompson
Executive Director
Panhandle Area Council
P.O. Box 880
Coeur d'Alene, ID 83814

Boundary County Board
of Commissioners
Attn: Betty C. Douglas
P.O. Box 419
Bonners Ferry, ID 83805

Chairman, Board of Commissioners
Bonner County Courthouse
Sandpoint, ID 83864

Chairman, Board of Commissioners
Kootenai County Courthouse
Coeur d'Alene, ID 83814

Chairman, Board of Commissioners
Teton County Courthouse
Driggs, ID 83422

Mr. Tom Fleming,
A-95 Coordinator
Region IV Development
Association, Inc.
725 Shoshone St. South
Twin Falls, ID 83301

Chairman, Board of Commissioners
Cassia County Courthouse
Burley, ID 83318

Minidoka County Planning
Commission
Attn: Mr. David Abo
P.O. Box 474
Rupert, ID 83350

Mr. Bob Cooper
Acting Executive Director
Clearwater Economic
Development Association
P.O. Box 8636
Moscow, ID 83843

Chairman, Board of Commissioners
Clearwater County Courthouse
Orofino, ID 83544

Chairman, Board of Commissioners
Nez Perce County Courthouse
Lewiston, ID 83501

Mr. Bob Taisey
A-95 Coordinator
Ida-Ore Regional Planning
and Development Association
P.O. Box 311
Weiser, ID 83672

Chairman, Board of Commissioners
Elmore County Courthouse
Mountain Home, ID 83647

Chairman, Board of Commissioners
Shoshone County Courthouse
Wallace, ID 83873

Chairman, Board of Commissioners
Latah County Courthouse
Moscow, ID 83843

Chairman, Board of Commissioners
Gem County Courthouse
Emmett, ID 83617

Mr. Gary Jeppson
A-95 Coordinator
East Central Idaho Plng.
and Development Assn.
P.O. Box 330
Rexburg, ID 83440

Renee Youree
Southeast Idaho Council of Governments
P.O. Box 4169, 403 North Main
Pocatello, ID 83201

Chairman, Board of Commissioners
Bonneville County
605 N. Capital Avenue
Idaho Falls, ID

Chairman, Board of Commissioners
Bingham County
Blackfoot, ID

Idaho Public Utilities Commission
Statehouse
Attn: Curtis Winterfield
Boise, ID 83720

Lincoln County Dept. of
Planning
Attn: Ken C. Peterson
418 Mineral Avenue
Libby, MT 59923

Missoula Planning Office
Attn: W. A. Walton, Director
301 N. Alder
Missoula, MT 59801

Flathead County Areawide Planning
Organization
Room 414, Courthouse East
723 5th Ave. East
Kalispell, MT 59901

Mineral County Planning Office
County Courthouse
Superior, MT 59872

Butte-Silver Bow Planning Board
Attn: Charles M. Rose, Planner
Silver Bow County Courthouse
Butte, MT 59701

Mr. Sandy O. Reierson
Chairman, Board of Commissioners
Powell County Courthouse
Deer Lodge, MT 59722

Anaconda-Deer Lodge County
Planning Board
Attn: Roberta Chandler,
Director
P.O. Box 902
Anaconda, MT 59711

Clearwater Economic Development
Association
Attn: Dan Green, Executive, Director
P.O. Box 8636
Moscow, ID 83843

Chairman, Board of Commissioners
Coos County Courthouse
Coquille, OR 97423

Chairman, Board of Commissioners
Curry County Courthouse
Gold Beach, OR 97444

Chairman, Board of Commissioners
Douglas County Courthouse
Roseburg, OR 97470

Chairman, Board of Commissioners
Deschutes County Courthouse
Bend, OR 97701

Chairman, Board of Commissioners
Umatilla County Courthouse
Pendleton, OR 97801

Crook County Planning Dept.
Courthouse
Prineville, OR 97754

Mr. William Hagman, Exec. Director
District 4 Council of Governments
No. 7 Wellsher Building
460 SW. Madison Street
Corvallis, OR 97330

Chairman, Board of Commissioners
Harney County Courthouse
Burns, OR 97720

Chairman, Board of Commissioners
Lake County Courthouse
Lakeview, OR 97630

Chairman, Board of Commissioners
Union County Courthouse
La Grande, OR 97850

Chairman, Board of Commissioners
Gilliam County Courthouse
Condon, OR 97823

Chairman, Board of Commissioners
Morrow County Courthouse
Heppner, OR 97836

Chairman, Board of Commissioners
Sherman County Courthouse
Moro, OR 97039

Chairman, Board of Commissioners
Wasco County Courthouse
The Dalles, OR 97058

Hood River County Board of
Commissioners
Attn: Ken Kirby
Hood River County Courthouse
4th and State Streets
Hood River, OR 97031

Chairman, Board of Commissioners
Klamath County Courthouse
Klamath Falls, OR 97601

Ms. Kathy Keene *
A-95 Coordinator
Lane Council of Governments
Lane County Public Service Bldg.
North Plaza Level
125 8th Avenue, E.
Eugene, OR 97401

Chairman, Board of Commissioners
Lane County Courthouse
Eugene, OR 97401

Chairman, Board of Commissioners
Marion County Courthouse
Salem, OR 97301

Chairman, Board of Commissioners
Polk County Courthouse
Dallas, OR 97338

Chairman, Board of Commissioners
Yamhill County Courthouse
McMinnville, OR 97128

Chairman, Board of Commissioners
Benton County Courthouse
Corvallis, OR 97330

Lincoln County Board of
Commissioners
Attn: Albert R. Strand, Chairman
225 W. Olive Street
Newport, OR 97365

Linn County Board of Commissioners
Attn: William L. Offutt
P. O. Box 100
Albany, OR 97321

Chairman, Board of Commissioners
Clackamas County Courthouse
Oregon City, OR 97045

Chairman, Board of Commissioners
Columbia County Courthouse
St. Helens, OR 97051

Chairman, Board of Commissioners
Multnomah County Courthouse
Portland, OR 97201

Chairman, Board of Commissioners
Washington County Courthouse
Hillsboro, OR 97123

Mr. Jack Lesch, Executive Director
Clatsop-Tillamook
Intergovernmental Council
P.O. Box 488
Cannon Beach, OR 97110

Chairman, Board of Commissioners
Clatsop County Courthouse
Astoria, OR 97103

Tillamook County Board of
Commissioners
Attn: Granville Simmons
P. O. Box 152
Tillamook, OR 97141

Andrew F. Leckie, Chairman
Wheeler County Board of Commissioners
County Courthouse
Adams Street
Fossil, OR 97830

Washington County, Oregon
Mr. Michael C. McCloskey
Assistant to County Administrator
150 North First Street
Hillsboro, OR 97123

Mr. Alan DeLaubenfeld, Administrator
Grant-Lincoln-Adams County Conference
of Governments
Courthouse
P.O. Box 338
Ephrata, WA 98823

Chairman, Board of Commissioners
Adams County Courthouse
Ritzville, WA 99169

Chairman, Board of Commissioners
Grant County Courthouse
P.O. Box 37
Ephrata, WA 98823

Chairman, Board of Commissioners
Lincoln County Courthouse
Davenport, WA 99122

Chairman, Board of Commissioners
Garfield County Courthouse
Pomeroy, WA 99347

Chairman, Board of Commissioners
Benton Conty Courthouse
Prosser, WA 99350

Chairman, Board of Commissioners
Chelan County Courthouse
Wenatchee, WA 98801

Chairman, Board of Commissioners
Clallam County Courthouse
County Courthouse
Port Angeles, WA 98362

Mr. Richard Hines, Coordinator
Regional Planning Council
of Clark County
P.O. Box 5000
Vancouver, WA 98663

Chairman, Board of Commissioners
Clark County Courthouse
1200 Franklin
Vancouver, WA 98660

Chairman, Board of Commissioners
Walla Walla County Commissioner
Walla Walla, WA 99362

Chairman, Board of Commissioners
Cowlitz County Courthouse
County Courthouse
Kelso, WA 98626

Chairman, Board of Commissioners
Wahkiakum County Courthouse
Cathlamet, WA 98612

Chairman, Board of Commissioners
Douglas County Courthouse
Waterville, WA 98858

Chairman, Board of Commissioners
Ferry County Courthouse
Republic, WA 99166

Chairman, Board of Commissioners
Pend Oreille County Courthouse
Newport, WA 99156

Chairman, Board of Commissioners
Stevens County Courthouse
Colville, WA 99114

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Attachment A

LETTERS RECEIVED ON
REVISED DRAFT ROLE ENVIRONMENTAL IMPACT STATEMENT

TABLE OF CONTENTS

Attachment A

TABLE OF CONTENTS (Continued)

Letter #1

Caroline Imports, Exports
909 W. Central Av:205; Missoula, Montana. 59801

April 3, 1980

Re: Conservation of energy.
HYD, Thermal; Steam powered Planes and vehicles

U.S.,Dept. of Energy
Bonneville Power Administration.
P.O.BOX 3621
PORTLAND, OREGON. 97208

Dear Sirs:

In reply to your letter of April 2, 1980; thank you,

Yes I have studied the revised Draft Environmental Impact Statement concerning BPA's Role in the Development of the Pacific Northwest Power Supply System, Including Its Participation in a Hydro-Thermal Power Program. i,e, "Role EIS."

Not being there, I can only say, that it seems to me, that you have not proceeded quite far enough, But I am absolutely sure, That My System, would not only work, but that it would develope sure and smooth power continually day or night, without any peak-loads to interfere with full power at all times.

Your Marketing and Customer Services would be under full control, and therefore your potential for environmental increase in volumn, could, and would accordingly develope and increase, just as fast as we could apply my theory to your dams, and besides your dams would have their water supply to be used for irrigation, or what-else.

Every Turbine in each Dam could supply it's full load of electrcity, and do it smoothly and easily. There does not need to be any black-outs, or shut-downs, For the power will be at the Engi-neers fingertips.

And I believe that I can assure you of the (ESA) that it cannot endanger any ESA Species; And I will guarantee, that we will be responsible to that effect. In fact it should be beneficial to all wildlife, as well as to all fish or fur-bearing animals. I love nature and would not want to injure or destroy any of it.

The potential of this is fulfilling for you, but what would be my benefits? That is what are the possibilities of my future? I will be easy to deal with, as I still hope to have ½ of my monies in U.S.Government bonds.

yours truly

Caroline Johnston
CAROLINE JOHNSTON. president,
909 W. Central Ave: 205
Missoula, Montana. 59801

/cj

Installment #100,000.00 down + as soon as I prove it, then #10,000.00 per mo. each. — Caroline Johnston. CJ

Letter #2

DONALD B. SLAUGHTER
ATTORNEY AT LAW

19708 - 1st Avenue So.
Seattle, WA 98148
(206) 878-2796

"Justice knoweth no balance, but that set by each's own time, value and circumstance."

Home:

Box 98376
Des Moines, Wash. 98188

April 6, 1980

UNITED STATES DEPARTMENT OF ENERGY
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

Dear Sirs,

This is to acknowledge receipt of the Revised Draft Environmental Impact Statement at my home address. Fortunately, the statement was forwarded to my new box number. My old address was:

Mr. Donald B. Slaughter
Box 89292
Des Moines, Washington 98188

My new home address is:

Mr. Donald B. Slaughter
Box 98376
Des Moines, Washington 98188

My business address is correct as given above (e.g. 19705 - 1st Ave S., Seattle, Washington, 98148) and I am a sole practitioner. At the time I sent my original comments in to you, I was a law student; since then I have progressed some, finishing my degree in law and passing the Washington State Bar Examination, as will be noted below in my new comments.

Yours Truly,

Don Slaughter
Donald B. Slaughter

New and Revised Comment on the Revised Environmental Impact Statement on power for the Northwest by The Bonneville Power Administration, for the Final Environmental Impact Statement to be issued.

April, 1980

Power in the Northwest: An analysis:

Revised.

by Donald B. Slaughter*

* B.A. in Communications, Univ. of Wash.,1975; J.D. (law), Univ. of Puget Sound, 1978; admitted to the bar of the State of Washington in May, 1979.

Letter #2 (continued)

index

Part I. Introduction

I have researched the question of energy seriously for some five years [redacted] now, since 1975. I have collected four notebooks of information on general energy topics (divided into different subjects through internal indexing), and have three notebooks on solar energy generally, one notebook on space satellite solar generation, and one notebook on nuclear power generation. This is a total of some nine (9) notebooks of articles and other data (such as personal communications with experts in geothermal, tidal, energy storage and nuclear power sources) that I have collected over those five years. In addition, besides sending a prior Comment on this B.P.A. statement in 1977, I have since participated in a federal regional seminar on solar energy in the summer of 1978. I have actively proposed new ideas on how to use energy as well as having simply read what others have done. So despite my lack of direct experience in the power industry or engineering credentials, I have some knowledge upon which to make intelligible remarks on this subject.

Part II. The National Picture

I think it is worth repeating my earlier assertions

in my prior Comment that the Northwest must do more than simply plan for its own power needs; it must recognize as an area that power in it will be drained off by federal decisions when future crises come, and in any case we are part of a national power pool. I believe this area of inquiry has yet to be seriously and properly addressed. 1

Part III. Shortcomings in the Revised Environmental Impact Statement

A. Regarding Wind systems

This is doubtless partly a function of timing, but the Figure IV-1 on page IV-5 of the Revised Statement, showing power plants existing, approved or under consideration in the Northwest, left out a number of wind generating facilities currently under preparation in southern Washington state (near Goldendale, Washington) for use along the Columbia River Gorge. I believe that every effort should be made to include their existence, and to comment on their impact on the Northwest scene (as in the potential they represent) in the Final Environmental Impact Statement. 2 3

B. Regarding Geothermal systems

On page IV-147, referring to the U.S. Geological Survey's search for geothermal power in the Northwest, you state that " it appears... very little potential (has been) identified for Montana and Washington." 4

It seems difficult if not impossible for this author to believe that Washington state does not have enormous geothermal potential. I agree that electrical potential temperature gradients have not been extensively found in Washington state; but there has been almost no serious exploration here!

How can one claim a state with no less than five dormant volcanos of significance, one of which is now active, along one of the most geologically active faults in the world, has no geothermal potential? (Or "very little" potential?) Your own statement has conceded that little if any serious drilling for geothermal wells has been done.

I think the U.S. Geological Survey's statement regarding Washington state would be better summarized as saying "little geothermal potential has been found in Washington, but there is significant geologic activity in that state and much research remains to be done. Further surveys and test drillings are probably indicated as a wise and prudent measure, before any conclusions as to whether wide-scale potential for economically feasible binary or "hot rocks" geothermal power generation exists in Washington state are to be reached.'

I wish it understood in context that I am referring here to electrical generating potential, and not just to

space heating or industrial uses of geothermal heat.
The section I directed your attention to refers to
power generation potential.

C. Regarding Nuclear Systems

The statement on page IV-163 on costs of nuclear
energy, relating to the uranium availability question,
is totally inadequate. First, what is the cost of
a uranium shortage, if one is unable to obtain uranium
at all? There are already some 10 utilities which have
so far been unable to line up uranium supplies for all the way up until
the year 2,000. The breeder reactor, under the best
scenario, would not be functioning in significant numbers
until 1995, and could therefore within its own fuel cycle
not produce significant amounts of commercially available
fuel until 2010 or 2020 (it would take a liquid metal
fast breeder reactor 20 to 30 years to produce the fuel 5
equivalent to what it itself uses.) In addition, the real
reason for the cost increase in uranium is a new cartel of
uranium producers has been formed, and the United States is
and will increasingly continue to be dependent upon uranium
imports. It is absolutely improper to exclude mentioning
these vitally material facts in your environmental impact
statement. There is indeed a serious question as to whether
there will be sufficient fuel supplies for U.S. commercial
reactors over the next 20 years--and such a real shortage
could inevitably cause price increases that would be signi-

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ficant.

Also, in talking about operating problems for a nuclear plant
on the same page (IV-163) you fail to mention the possibility
of a catastrophic accident such as occurred at Three Mile
Island. Nor is there any discussion of what the impact
of such an accident would be on costs under your cost
section on that page. Hard material is now coming in
from the Three Mile Island accident on such costs. Also, 6
the accidents at Idaho Falls in 1954 with a breeder, in
1961 with a small experimental reactor, in 1966 near
Detroit at the Enrico Fermi reactor, and in 1975 at
Brown's Ferry, Alabama should be cited along with Three
Mile Island as strong evidence of a continuing historical
trend of a probability of serious accidents occurring
every so often for so many reactor years of operation in
the United States.

Finally, your cost section on uranium and nuclear
plant operations generally failed to mention the cost
impact of BPA guaranteeing purchases of power from nuclear 7
of other power generating sources without contractually
agreed limits on costs in advance. This is significant
because of actual purchases which have been made or consi-
dered by BPA relating to the construction and generation of
power by nuclear means by the Washington Public Power Supply System
(W.P.P.S.S.) Since tremendous cost inflation has already

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struck the W.P.P.S.S. projects, this is not exactly a
moot or hypothetical question. Of course, the issue of
guaranteed purchases and their cost impacts is more general
then simply when applied to nuclear plants; any guaranteed
purchase plan for any source of power generation may be
subject to similar abuses.

On Page IV-165 you cite costs for de-commissioning
of nuclear plants that many critics consider way too low, 8
apparently based on Battelle Northwest's estimates. You
should cite your sources for that low figure, and concede
the figure to be contested.

I wish to update prior remarks I made on the fusion
reactor (which because of its long lead time you seem not
to have discussed much anyway.) The fusion reactor does
have serious and significant negative environmental impacts, 9
such as releasing increble amounts of neutron irradiation
into its neighborhood even with a massive "lithium" first
wall, and creating radioactive isotopes which are not
simply radioactive, and potentially gaseous, but also which
can be used to make hydrogen bombs.

D. Regarding Solar systems

You also left out Solar Power Satellites as a topic;
they are some ways off, but if they do well on preliminary
designs they could come into the picture bedore the year
2,000, so they probably should at least be cursorily dealt 10
with. Their negative impacts of microwaves, antennas, reflection
of light to earth and pollution from rockets taking off have

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become somewhat infamous.

E. Regarding likely Demand for power

Although you discuss conservation in a generalized
way, you fail to discuss mandatory conservation in a favorable
way, noting a potential decrease in utility business
and emphasizing voluntary programs (see IV-102).
However, there is no extensive discussion of likely
demand patterns and increases or decreases regardless
of which scenario (as on IV -193) is considered. This
I consider highly improper. To make it all worse, you
fail to discuss the most important general energy question
of our time, which involves the real reason we are facing 11
an energy crisis: What will happen when people start
switching massively off of petroleum for use in trans-
portation and heating? This obviously must happen
sooner or later, and will cause an incredibly massive
increase of anywhere from 50% to 150% in demand for electrical
generation--and this could occur, given the volital interna-
tional situation, within 10 to 15 years. Would not
major and mandatory conservation measures be essential
in such a scenario? Should not such a scenariow be
seriously considered in the BPA statement?

PART IV.
CONCLUSION

In conclusion, the BPA and the people of the Northwest
should not be tied to nuclear or coal power as the primary
or sole source of major new power generation in the years

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Letter #2 (continued)

years to come. Geothermal power, mandatory conservation and installation of solar heating where feasible, and other alternatives such as wind power generation are available today or will be within a year or two as sources of major power generation. If all of these alternatives were used in tandem, with development of low head hydro and coal generators as last measure backups, all the Northwest's power needs for about 10 to 20 years could be met without any new expensive and risky nuclear plants.

At that time, the decision as to whether nuclear power is safe and fuel is available can be better made. In addition, in 10 to 20 years it will have become clear whether it is likely that photovoltaic solar power generation will become cost-competitive with other major energy sources.

Also, during the next 10 to 20 years, the BPA should coordinate its efforts with other national power pools to develop pumped storage, compressed air storage, weights storage, and whatever other reasonable storage systems 12
(such as batteries or compressed springs) present themselves, because: (1) storage systems generally have minimal negative environmental impacts; (2) they effectively increase generating capacity; and (3) development of large-enough scale energy storage capacity will make large-scale use of alternatives such as wind and photovoltaic solar practical if and when they are available and ready for use.

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Letter #3

STATE OF WASHINGTON
Dixy Lee Ray
Governor

WASHINGTON STATE PARKS AND RECREATION COMMISSION
7150 Clearwater Lane, KY-11, Olympia, Washington 98504 206/753-5757
Jan Tveten, Director

April 7, 1980

35-2650-1820
Revised DEIS - The Role of the BPA in the Pacific Northwest Power Supply System
(E-1898)

Environmental Manager
Bonneville Power Administration
P.O. Box 3621 - SJ
Portland, Oregon 97208

Gentlemen:

The staff of the Washington State Parks and Recreation Commission has reviewed the above-noted document and does not wish to make any comment.

Thank you for the opportunity to review and comment.

Sincerely,

David W. Heiser, E.P., Chief
Environmental Coordination

DWH/PJP:jh

Letter #4

CROSBY LIBRARY
GONZAGA UNIVERSITY
East 502 Boone Avenue Spokane, Washington 99258

April 4, 1980

Bonneville Power Administration
U. S. Department of Energy
P.O. Box 3621
Portland, Oregon 97208

Gentlemen:

Thank you for your letter of April 2 and the revised draft of the Environmental Impact Statement on The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System.

We appreciate having this publication for our library patrons. Thank you for sending it.

Sincerely yours,

Robert L. Burr
Director

rs

Letter #5

Advisory Council On Historic Preservation

ADVISORY COUNCIL ON HISTORIC PRESERVATION
LAKE PLAZA SOUTH, SUITE 616
44 UNION BOULEVARD
LAKEWOOD, COLORADO 80228

1522 K Street NW.
Washington D.C.
20005

OFFICIAL FILE COPY
No. Date APR 28 1980
Referred To:
Action Taken
ANS. NO ANSW
By Date

April 21, 1980

Mr. Sterling Munro
Administrator
Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

Dear Mr. Munro:

This is in response to your request of April 2, 1980, for comments on the revised draft environmental statement (RDES) for the Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System. Pursuant to its responsibilities under Section 102(2)(C) of the National Environmental Policy Act of 1969, the Council has determined that this RDES does not demonstrate compliance with Section 106 of the National Historic Preservation Act of 1966 (16 U.S.C. Sec. 470f, as amended, 90 Stat. 1320). However, it appears that the Department of Energy understands its responsibilities and will carry them out in the future.

Should you have any questions, please contact Betty J. LeFree at (303) 234-4946, an FTS number.

Sincerely yours,

Louis S. Wall
Chief, Western Division of Project Review

Letter #6

MONTANA HISTORICAL SOCIETY

HISTORIC PRESERVATION OFFICE

225 NORTH ROBERTS STREET • (406) 449-4584 • HELENA, MONTANA 59601

April 23, 1980

Mr. John E. Kiley, Environmental Manager
Bonneville Power Administration
Box 3621
Portland, Oregon 97208

RE: E-80-04-02
Revised Draft EIS Role of Bonneville Power

Dear Mr. Kiley:

As this draft statement reflects policy decisions, I will have no comment at this point. Please advise me early in your project planning prior to implementing any proposal in the State of Montana. I and my staff will be pleased to assist you in evaluating impacts to historic and cultural properties, and to advise you in compliance with Sec. 106 of the Historic Preservation Act as in 36CFR800, and with Executive Order 11593.

Thank you for permitting me to review your draft.

Sincerely,

Dr. Robert Archibald
Acting SHPO

RA/EV/prb

cc Clearinghouse

Letter #7

OFFICIAL FILE COPY
MAY 5 1980

UNIVERSITY OF WASHINGTON
SEATTLE, WASHINGTON 98195

April 30, 1980

Institute for Environmental Studies
Engineering Annex, FM-12

Honorable Sterling Munro, Administrator
Bonneville Power Administration
Box 3621
Portland, Oregon 97208

Dear Mr. Munro:

We are writing to offer comments on the revised draft "Role EIS," DOE/EIS-0066 (April 1980).

While we have not undertaken a detailed reading of the impact statement, a number of substantive points emerge on a quick review:

--the discussion of peaking uses of the hydropower system is seriously inadequate. Especially because this is a "tiered" environmental analysis, the programatic implications of hydro-thermal operation must be coherently addressed in this EIS. Yet a few brief and general paragraphs in Chapter IV are all that is devoted to an intricate and (to our understanding) uncertain problem. 1

--the discussion of radioactive-waste management at Pages IV-46 and IV-47 is not only extremely brief for a program which may, in future years, lead to deployment of a sizable number of nuclear reactors, but it is out of date in referring to federal documents which have been superseded by later ones. In particular, on 12 February 1980, President Carter issued new guidance with respect to federal policies on nuclear waste management. These implement the findings of the Interagency Review Group on Nuclear Waste Management, which reported to the President in March 1979; the most recent summary of governmental policy, issued by the U.S. Department of Energy, is the draft environmental impact statement, Management of Commercially Generated Radioactive Waste, issued in April 1979. Citizens relying on the revised EIS from BPA to find further information on this tangential but important subject are not well served by this draft. 2

Recycled Paper

Honorable Sterling Munro
April 29, 1980
Page 2

More generally, these points illustrate an implicit problem with program environmental analyses. That is the need, as a program evolves, for continued re-evaluation of program-level effects. We have suggested in Electric Power and the Future of the Pacific Northwest that BPA periodically issue supplements to the Role EIS, say on a biennial basis. These supplements should implement the re-evaluation of effects of the regional program, in light of changes in circumstances. Our expectation would be that these supplemental volumes could be quite short, referring back to earlier volumes for basic descriptions of the program and its alternatives, concentrating instead upon the ongoing implementation of a program selected. The revised draft underscores the need for such supplements, as well as improvements in this draft. 3

We hope these comments will be constructive in improving the EIS.

Sincerely,

Kai N. Lee

Kai N. Lee, Assistant Professor
Environmental Studies and Political Science

Marion Marts

Marion E. Marts, Professor
Geography and (Adjunct) Environmental Studies

KNL/MEM:BCP

Letter #8

VICTOR ATIYEH
GOVERNOR

Executive Department

155 COTTAGE STREET N.E., SALEM, OREGON 97310

May 6, 1980

John E. Kiley
Environmental Manager
Bonneville Power Administration
P.O. Box 3621
Portland, OR. 97208

Dear Mr. Kiley:

Role of BPA in Pacific Northwest Power Supply System
PNRS 8004 4 180

Thank you for submitting your revised draft Environmental Impact Statement for State of Oregon review and comment.

Your revised draft was referred to the appropriate state agencies. The Department of Land Conservation and Development, and Historic Preservation offered the enclosed comments which should be addressed in preparation of your final Environmental Impact Statement.

We will expect to receive copies of the final statements as required by Council of Environmental Quality Guidelines.

Sincerely,

INTERGOVERNMENTAL RELATIONS DIVISION

Kay F. Wilcox

Kay Wilcox,
A-95 Coordinator

KW:cb
Enclosures

Letter #8

OREGON PROJECT NOTIFICATION AND REVIEW SYSTEM

STATE CLEARINGHOUSE

Intergovernmental Relations Division
155 Cottage ST SE
Salem, Oregon 97310, Phone: 378-3732

STATE A-95 REVIEW ADDENDUM

APPLICANT: BPA

PROJECT TITLE: Role fo BPA In Pacific Northwest Power Supply System

PNRS #: 8004 4 180

DATE: May 9, 1980

The State Clearinghouse has received additional comments from State Lands subsequent to our conclusion letter of May 6, 1980 please see copy (ies) attached for your attention.

Additional Clearingnouse comments:

(x) Please consider this letter and enclosure(s) an addendum to our previous letter.

(x) A copy of this letter and enclosure(s) should be forwarded to the federal funding agency as required by OMB A-95.

If you have questions please contact the State Clearinghouse at the above address and telephone number.

Letter #8

OREGON PROJECT NOTIFICATION AND REVIEW SYSTEM

STATE CLEARINGHOUSE

Intergovernmental Relations Division
155 Cottage St SE, Salem, Oregon, 97310
Phone Number: 378-3732

RECEIVED
APR - 7 1980
DIVISION OF STATE LANDS

PNRS STATE REVIEW

Project #: 8004 4 180 Return Date: [illegible]

ENVIRONMENTAL IMPACT REVIEW PROCEDURES

If you cannot respond by the above return date, please call to arrange an extension at least one week prior to the review date.

ENVIRONMENTAL IMPACT REVIEW
DRAFT STATEMENT

( ) This project has no significant environmental impact.

( ) The environmental impact is adequately described.

(X) We suggest that the following points be considered in the preparation of a Final Environmental Impact Statement.

( ) No comment.

Remarks

Chapter IV Environmental Consequences should include in the Impacts of the Hydrosystem: 1. Loss of aggregate resources to downstream recruitment. 1

2. Increased erosion due to maintained water levels over an extended period of time. 2

Agency Lands By [signature]

Letter #8

OREGON PROJECT NOTIFICATION AND REVIEW SYSTEM

STATE CLEARINGHOUSE

Intergovernmental Relations Division
155 Cottage St SE, Salem, Oregon, 97310
Phone Number: 378-3732

PNRS STATE REVIEW

Project #: [illegible] Return Date: [illegible]

ENVIRONMENTAL IMPACT REVIEW PROCEDURES

If you cannot respond by the above return date, please call to arrange an extension at least one week prior to the review date.

ENVIRONMENTAL IMPACT REVIEW
DRAFT STATEMENT

( ) This project has no significant environmental impact.

( ) The environmental impact is adequately described.

(✓) We suggest that the following points be considered in the preparation of a Final Environmental Impact Statement.

( ) No comment.

Remarks

Draft EIS BPA - Pacific Northwest Power System

See cultural resources & 36CFR800

Agency SHPO By [signature]

Letter #8

State wide JHC

OREGON PROJECT NOTIFICATION AND REVIEW SYSTEM

STATE CLEARINGHOUSE

DEPARTMENT OF LAND CONSERVATION AND DEVELOPMENT
APR 8 1980
SALEM

Intergovernmental Relations Division
155 Cottage St SE, Salem, Oregon, 97310
Phone Number: 378-3732

PNRS STATE REVIEW

Project #: [illegible] Return Date: MAY 23 1980

ENVIRONMENTAL IMPACT REVIEW PROCEDURES

If you cannot respond by the above return date, please call to arrange an extension at least one week prior to the review date.

ENVIRONMENTAL IMPACT REVIEW
DRAFT STATEMENT

( ) This project has no significant environmental impact.

( ) The environmental impact is adequately described.

(✓) We suggest that the following points be considered in the preparation of a Final Environmental Impact Statement.

( ) No comment.

Remarks

It is expected that federal agency plans will conform and be coordinated with the comprehensive plans of cities and counties 3

Agency LCDC By JH Clapsaddle

Letter #9

Homberg Farms Inc.
Rt. #2, Box 22
Odessa, Washington 99159

5-6-80

Enviromental Manager
Bonneville Power Administration:

We are writing this letter in response to the revised draft of the Environmental Impact Statement.

1. We believe that the preference clause should be maintained and that no new utilities should become preference customers.
2. The operation of the one utility concept of the Regions Generation and Transmission should be maintained.
3. We in the Northwest need to be assured of a continued supply of electricity.
4. We also encourage and endorse Alternative 3, as outlined in the Revised Draft E.I.S. giving B.P.A. an increased role in the region.

Sincerely yours,
Lamar Homberg
Homberg Farms Inc.
Lamar Homberg Pres.

Letter #10

F. H. STOLTZE LAND & LUMBER CO.
Lumber Manufacturers
Box 490 COLUMBIA FALLS, MONTANA 59912

May 7, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Ore. 97208

Dear Sir:

I have reviewed your EIS on "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System". Of the alternatives presented, 3 or 4 should be adopted. However, they should not be adopted because they are "environmentally preferable" but because they appear to plan for the future electrical needs of the area. We must provide the electricity needed for a stable industry in the West.

Sincerely yours
F. H. STOLTZE LAND & LBR. CO.
Ronald Buentemeier
Ronald Buentemeier
Timber Manager

RB/bb

Letter #11

3733 Jackson
Corvallis OR 97330
5/9/80

BPA

Back in 1977 I saw an announcement of the publication "Role of BPA in PNW power Supply System". Being interested in the electrical power problem I wrote for this and found it informative.

Perhaps because of this I was mailed the revised draft of the EIS ~~statement~~ April 1980. Time has permitted only a cursory examination and I am really not knowledgeable enough on these matters to make a contribution.

I will however express a few biases.

1. My examination of the alternatives leads me to favor alternative #3. Having made this decision from examining the Summary and following this with a study pages III-1 to III-60, I noted the information on pages I-32 & 34.

2. I am not opposed to nuclear power. I would agree for it but only if -

   a. A better safety procedure can be assured & demonstrated.

   b. It is part of an energy program that uses nuclear fission as a temporary alternative to other sources. I put coal in the same category

3. Conservation will come only as economics makes it practical. I see how my friends in Washington waste power because of low rates.

4. We must move toward reserving electricity as energy of motion not use other source for heat.

5. I recognize the need for electrical power for economic growth but we tend to let the pendulum swing too far. Dam construction proceeded ruthlessly before needed technology could be developed to preserve the fish resource. Now I feel power must pay the price and make some cut backs until we catch up on fisheries.

6. I am not sure I understand the term "preferential customer". Perhaps once for developmental purposes these kinds of rates were necessary or at least thought appropriate. I do not see this largess as being appropriate today. I presume it has become involved in political activity but if needy people need assistance give them a grant to meet a reasonable need. It seems to me that these preferential rates have long been outdated.

7. I responded to a PP&L questionnaire giving preference to source of new power as follows.

   1st a. Nuclear - for short run after the disposal of waste method is agreed upon nationally

   b. Wind, Solar

   c. Geothermal

   d. Coal - as last resort and only for short run.

   e. Small hydro - Most of them are environmentally unacceptable.

Yours truly
W. G. Nibler
Nibler

Letter #12

BUTLER-WILLIAMS

Butler ASSOCIATES, INC. — A JOINT VENTURE
WILLIAMS BROTHERS ENGINEERING COMPANY

P.O. BOX [illegible]
TULSA, OKLAHOMA 74145

May 9, 1980

Mr. John E. Kiley
Environmental Manager
U. S. Department of Energy
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, Oregon 97208

Re: Comments on Bonneville Power Administration's Role EIS

Dear Mr. Kiley:

We have reviewed the revised Draft Environmental Impact Statement DOE/EIS-0066 dated April, 1980, which presents "The Role Of The Bonneville Power Administration In The Pacific Northwest Power Supply System, Including Its Participation In A Hydro-Thermal Power Program."

In your April 2, 1980, letter you requested that we review and comment on the revised Role EIS by June 12, 1980. As you are most likely aware, Northern Tier Pipeline Company (NTPC) is progressing with its efforts to obtain the state and federal permits necessary to construct its planned pipeline system from Port Angeles, Washington, to Clearbrook, Minnesota. It is anticipated that all necessary permits will be in hand by late 1980.

In our letter of December 3, 1977, (copy attached) we submitted to you on behalf of NTPC preliminary information on its planned pipeline system to aid in the preparation of the Role EIS for Bonneville Power Administration.

Since the original draft Role EIS has been substantially revised, we take this opportunity to submit the following updated information on power requirements of the proposed Northern Tier Pipeline system:

Exhibit 1 is a summary of the total power requirements for the project.

Exhibit 2 is a summary by state of the initial and ultimate power requirements for the project.

Exhibit 3 shows the initial and ultimate power requirements for the proposed NTPC marine terminal.

Exhibit 4 shows the initial and ultimate power requirements for the proposed NTPC pump stations.

Mr. John E. Kiley
May 8, 1980
Page 2

Exhibit 5, pages 1 and 2, shows the power companies serving the proposed NTPC facilities.

Exhibit 6, pages 1 and 2, shows effect of insufficiency notices from Bonneville Power Administration on the utility companies serving proposed NTPC facilities.

Figure A. 1-2, Proposed Location of NTPC Facilities and Pipeline Construction Sections.

For your planning purposes, NTPC's present schedule calls for the system to be placed in operation in late 1983. At this time, NTPC does not have a firm schedule as to when the system would be expanded to its ultimate capacity.

We certainly appreciate being asked to review and comment on the revised Draft EIS on "The Role of Bonneville Power Administration in the Northwest Power System." Please contact us if you have any questions on the information provided.

Very truly yours,

Albert E. Whiteside

Albert E. Whiteside, P.E.

AEW:rs
Encls.
13.1.3.2
cc: T. C. Kryzer w/encls.
J. E. Latz "
W. C. Sage "
E. Baynard "
B. Wilcox "

NORTHERN TIER PIPELINE PROJECT

TOTAL POWER REQUIREMENTS

SUMMARY

	Initial Capacity (709,000 BPD)		Ultimate Capacity (933,000 BPD)	
	Demand MW	Annual Energy KWH (Million)	Demand MW	Annual Energy KWH (Million)
Marine Terminal	17.8	40.8	19.1	51.6
Pump Stations	121.1	991.2	243.6	2018.4
Delivery Facility (Clearbrook)	0.3	2.6	0.3	2.6
TOTAL	139.2	1034.6	263.0	2072.6

EXHIBIT 1

NORTHERN TIER PIPELINE PROJECT

POWER REQUIREMENTS BY STATE

	Initial Capacity (709,000 BPD)		Ultimate Capacity (933,000 BPD)	
	Demand MW	Annual Energy KWH (Million)	Demand MW	Annual Energy KWH (Million)
Washington	68.6	464.4	107.9	789.6
Idaho	12.3	102.0	19.4	160.8
Montana	42.2	333.6	96.2	790.8
North Dakota	15.8	132.0	30.0	250.8
Minnesota	0.3	2.6	9.5	80.6
TOTAL	139.2	1034.6	263.0	2072.6

EXHIBIT 2

NORTHERN TIER PIPELINE PROJECT

MARINE TERMINAL

POWER REQUIREMENTS

	Initial Capacity (709,000 BPD)		Ultimate Capacity (933,000 BPD)	
	Demand MW	Annual Energy KWH (Million)	Demand MW	Annual Energy KWH (Million)
Tanker Unloading Facilities	15.6	33.6	15.6	43.2
Onshore Storage Facilities	2.2	7.2	3.5	8.4
TOTAL	17.8	40.8	19.1	51.6

EXHIBIT 3

NORTHERN TIER PIPELINE PROJECT
PUMP STATION POWER REQUIREMENTS[a]

Pump Station	Initial Power Requirements (709,000 bpd)			Ultimate Power Requirement (933,000 bpd)		
State and County	Demand MW	Monthly Energy KWH (million)	Annual Energy KWH (million)	Demand MW	Monthly Energy KWH (million)	Annual Energy KWH (million
Washington						
Clallam	6.6	4.6	55.2	13.3	9.2	110.4
Snohomish	7.1	4.9	58.8	11.5	8.0	96.0
King	7.8	5.4	64.8	12.3	8.5	102.0
King	7.2	5.0	60.0	10.1	7.0	84.0
Kittitas	10.6	7.4	88.8	17.8	12.3	147.6
Grant	.3	.2	2.4	.3	.2	2.4
Adams	3.6	2.5	30.0	11.2	7.8	93.6
Spokane	7.6	5.3	63.6	12.3	8.5	102.0
Subtotal	50.8	35.3	423.6	88.8	61.5	738.0
Idaho						
Kootenai	4.8	3.3	39.6	7.4	5.1	61.2
Shoshone	7.5	5.2	62.4	12.0	8.3	99.6
Subtotal	12.3	8.5	102.0	19.4	13.4	160.8
Montana						
Sanders	6.1	4.2	50.4	16.0	11.1	133.2
Missoula	13.9	9.6	115.2	20.9	14.5	174.0
Powell	3.2	2.2	26.4	7.0	4.9	58.8
Broadwater	6.2	4.3	51.6	15.7	10.9	130.8
Wheatland	7.3	3.9	46.8	10.5	6.8	81.6
Garfield	-	-	-	13.5	9.4	112.8
Richland	5.5	3.6	43.2	12.6	8.3	99.6
Subtotal	42.2	27.8	333.6	96.2	65.9	790.8
North Dakota						
Williams	7.3	5.1	61.2	9.5	6.6	79.2
McHenry	-	-	-	9.9	6.9	82.8
Ramsey	8.5	5.9	70.8	10.6	7.4	88.8
Subtotal	15.8	11.0	132.0	30.0	20.9	250.8
Minnesota						
Polk	-	-	-	9.2	6.5	78.0
Total - Pipeline	121.1	82.6	991.2	243.6	168.2	2,018.4

Source: Northern Tier Pipeline Company 1978

[a] Rev. 1, March 30, 1979, Table 1.4-15. Submitted to BLM, Environmental Statement Team, Portland, Oregon. Butler Associates, Tulsa.

EXHIBIT 4

NORTHERN TIER PIPELINE PROJECT

POWER COMPANIES SERVING FACILITIES

Pump Station, Tanker Unloading, Delivery Facility	Serving Utility	New Facilities Required
Tanker Unloading Facilities	City of Port Angeles	1 69-KV switching station 2 mile double 69-KV line underground line 2-69/4.16-KV, substation
Port Angeles	Clallam County PUD	1 69-KV switching station 1 mile 69-KV, Double 69-KV underground line 2-69/4.16-KV substation
Arlington	Snohomish PUD NO. 1	5 miles 115-KV line 1-115/4.16-KV substation
Carnation	Puget Sound Power & Light	1 mile convert 55-KV line to 115-KV line 1-115/4.16-KV substation
Bandera	Puget Sound Power & Light	1 mile 115-KV line 1-115/4.16-KV substation
Ellensburg	Kittitas PUD NO. 1	0.5 miles 115-KV line 1-115/4.16-KV substation
	or	
	Puget Sound Power & Light	1 mile 230-KV line 1-230/4.16 substation
Quincy	Grant County PUD	2 miles 13.2-KV line 1-13.2/.48-KV substation
Odessa	Lincoln Electric Cooperative	8 miles convert 34-KV line to 115-KV line 1-115/4.16-KV substation
Plaza	Inland Power & Light Company	3 miles 115-KV trans. line 1-115/4.16-KV substation
Cataldo	Washington Water Power Company	1 mile 115-KV trans. line 1-115/4.16-KV substation
Enaville	Washington Water Power Company	1 mile 115-KV trans. line 1-115/4.16-KV substation
Paradise	Montana Power Co.	Approx. 10 miles 69-KV trans. line 1-69-KV substation

EXHIBIT 5
Page 1 of 2

POWER COMPANIES SERVING FACILITIES

Pump Station, Tanker Unloading, Delivery Facility	Serving Utility	New Facilities Required
Potomac	Montana Power Co.	Less than 1 mile 161-KV trans. line 1-161-KV substation
Elliston	Montana Power Co.	Approx. 1 mile 100-KV trans. line 1-100-KV substation
Townsend	Montana Power Co.	3-1/2 miles 100-KV line 1-100/4.16-KV substation
Harlowton	Montana Power Co.	15.4 miles 69-KV line 1-69/4.16-KV substation
Jordon	McCone Electric Co-op.	DOE substation 230-KV to 69-KV 42 mile 69-KV line 1-69-KV/4.16-KV substation
Richey	Montana-Dakota Utilities Co.	26 miles 57-KV line 1-67/4.16-KV substation
Tioga	Montana-Dakota Utilities Co.	7 miles 57-KV line 1-67/4.16-KV substation
	or	
	Williams Electric Co-op	8.5 miles 115-KV line 1-115/4.16-KV substation
Towner	Otter Tail Power Co.	1 mile 115-KV trans. line 1-115/4.16-KV substation
	or	
	Verendrye Elec. Co-op	2 miles 41.6-KV line 1-41.6/4.16-KV substation
Devils Lake	Otter Tail Power Co.	4 miles 115-KV trans. line 1-115/4.16-KV substation
Crookston	Otter Tail Power Co.	2 miles 115-KV trans. line 1-115/4.16-KV substation
Clearbrook Delivery Facilities	Otter Tail Power Co.	0.5 miles 4.16-KV line 1-4.16/.48-KV substation

EXHIBIT 5
Page 2 of 2

Letter #12 (continued)

NORTHERN TIER PIPELINE PROJECT

POWER AVAILABILITY

Location State & County	Pump Station Tanker Unloading, Delivery Facility	Serving Utility	Service Availability (Code Description[1])
Washington			
Clallam	Tanker Unloading Facilities	City of Port Angeles	M
Clallam	Port Angeles	Clallam County PUD	M
Snohomish	Arlington	Snohomish PUD No. 1	M
King	Carnation	Puget Sound Power & Light	M
King	Bandera	Puget Sound Power & Light	M
Kittitas	Ellensburg	Kittitas PUD No. 1	Y
		OR	
		Puget Sound Power & Light	M
Grant	Quincy	Grant County PUD	Y
Adams	Odessa	Lincoln Electric Cooperative	M
Spokane	Plaza	Inland Power & Light Company	Y
Idaho			
Kootenai	Cataldo	Washington Water Power Company	M
Shoshone	Enaville	Washington Water Power Company	M
Montana			
Sanders	Paradise	Montana Power Company	M
Missoula	Potomac	Montana Power Company	M
Powell	Elliston	Montana Power Company	M

EXHIBIT 6
Page 1 of 2

POWER AVAILABILITY

Location State & County	Pump Station, Tanker Unloading, Delivery Facility	Serving Utility	Service Availability (Code Description[1])
Broadwater	Townsend	Montana Power Company	M
Wheatland	Harlowton	Montana Power Company	M
Garfield	Jordon	McCone Electric Co-op	Y
Richland	Richey	Montana-Dakota Utilities Company	Y
North Dakota			
Williams	Tioga	Montana-Dakota Utilities Company	Y
		OR	
		Williams Electric Co-op	Y
McHenry	Towner	Otter Tail Power Co.	Y
		OR	
		Verendrye Elec. Co-op	Y
Ramsey	Devils Lake	Otter Tail Power Co.	Y
Minnesota			
Polk	Crookston	Otter Tail Power Co.	Y
Clearwater	Clearbrook Delivery Facilities	Otter Tail Power Co.	Y

[1]Y - Service Available
M - Depending on plant additions; service not refused
B - Hesitant because of insufficiency notices; service not refused

EXHIBIT 6
Page 2 of 2

utler Associates, Inc. SUITE 600 HARVARD TOWER / 4815 SOUTH HARVARD / TULSA, OKLAHOMA

8 December 1977

Mr. John E. Kiley
Environmental Manager
United States Department of Energy
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

Dear Mr. Kiley:

We have reviewed drafts of the Role Environmental Impact Statement (EIS)/Alumax EIS which presents the role of the Bonnevilla Power Administration in the Pacific Northwest Power Supply System.

In your letter of November 28, 1977, you requested any impacts which should be included in the Bonneville Power Administration EIS evaluation be submitted by December 14, 1977.

To aid in this evaluation, we are including the electric power requirements for the proposed Northern Tier Pipeline which will be a common carrier 42 and 40-inch diameter crude oil pipeline originating at a deepwater port facility at Port Angeles, Washington, and extending approximately 1,550 miles to Clearbrook, Minnesota. The port facility will receive crude oil delivered by tanker from Alaskan and foreign sources; the pipeline will have access to existing crude oil pipelines serving refineries in the Rocky Mountains, upper Midwest and Eastern United States as shown on the enclosed general route map of the proposed system.

We are in the process of submitting the description of the proposed action to the Bureau of Land Management in Portland, Oregon, who is the lead agency for preparation of the federal EIS for the Northern Tier Pipeline Project.

Tables number 1 and 2 show the estimated initial and ultimate power requirements for the Northern Tier Pipeline. These tables list requirements in Washington, Idaho, Montana and North Dakota.

Initial power requirements are shown in Table 1. Based on present forecasts, the initial power requirements would be required from 1981 through 1985.

Ultimate power requirements are shown in Table 2. Based on present forecasts, the ultimate power requirements would be required after 1985.

Mr. Kiley
8 December 1977
Page - 2

We certainly appreciate the opportunity to furnish this preliminary information to aid in your Role EIS for the Bonnevile Power Administration. Please contact us if you have any questions on the information provided.

Very truly yours,

A. E. Whiteside

A. E. Whiteside

AEW:lrk:197

cc: E. A. Puller
J. R. Beasley

Attachments:
General Route Map - Northern Tier Pipeline System
Table 1 Initial Power Requirements
Table 2 Ultimate Power Requirements

Letter #12 (continued)

TABLE 1

Initial Power Requirements
1981-1985
Northern Tier Pipeline

LOCATION	DEMAND MW	MONTHLY ENERGY KWH (MILLION)	ANNUAL ENERGY KWH (MILLION)
Port; Port Angeles, Washington	7.8	2.8	33.6
Clallam Co., Washington	11.2	8.1	97.2
Mason Co., Washington	5.4	3.9	46.8
Pierce Co., Washington	7.0	5.1	61.2
King Co., Washington	5.3	3.8	45.6
King Co., Washington	7.7	5.6	67.2
Kittitas Co., Washington	7.4	5.4	64.8
Lincoln Co., Washington	3.4	2.5	30.0
Spokane Co., Washington	7.3	5.3	63.6
Subtotal - Washington	62.5	42.5	510.0
Shoshone Co., Idaho	10.1	7.3	87.6
Subtotal - Idaho	10.1	7.3	87.6
Sanders Co., Montana	4.0	2.9	34.8
Missoula Co., Montana	5.2	3.8	45.6
Granite Co., Montana	7.9	5.7	68.4
Powell Co., Montana	5.1	3.7	44.4
Broadwater Co., Montana	6.0	4.3	51.6
Wheatland Co., Montana	-	-	-
Rosebud Co., Montana	3.4	2.5	30.0
Prairie Co., Montana	7.5	5.4	64.8
Subtotal - Montana	39.1	28.3	339.6
Stark Co., North Dakota	-	-	-
Burleigh Co., North Dakota	3.9	2.8	33.6
Trail Co., North Dakota	4.4	3.2	38.4
Subtotal - North Dakota	8.3	6.0	72.0
TOTAL - PIPELINE	120.0	84.1	1,009.2

TABLE 2

Ultimate Power Requirements
After 1985
Northern Tier Pipeline

LOCATION	DEMAND MW	MONTHLY ENERGY KWH (MILLION)	ANNUAL ENERGY KWH (MILLION)
Port; Port Angeles, Washington	7.8	3.6	43.2
Clallam Co., Washington	15.4	11.1	133.2
Mason Co., Washington	11.5	8.3	99.6
Pierce Co., Washington	8.4	6.1	73.2
King Co., Washington	7.4	5.4	64.8
King Co., Washington	10.6	7.7	92.4
Kittitas Co., Washington	13.1	9.4	112.8
Lincoln Co., Washington	11.9	8.6	103.2
Spokane Co., Washington	12.8	9.3	111.6
Subtotal - Washington	98.9	69.5	834.0
Shoshone Co., Idaho	16.1	11.7	140.4
Subtotal - Idaho	16.1	11.7	140.4
Sanders Co., Montana	10.9	7.9	94.8
Missoula Co., Montana	10.8	7.3	87.6
Granite Co., Montana	13.1	9.5	114.0
Powell Co., Montana	7.1	5.2	62.4
Broadwater Co., Montana	13.2	9.5	114.0
Wheatland Co., Montana	8.2	6.0	72.0
Rosebud Co., Montana	11.7	8.4	100.8
Prairie Co., Montana	9.4	6.8	81.6
Subtotal - Montana	84.4	60.6	727.2
Stark Co., North Dakota	9.7	7.0	84.0
Burleigh Co., North Dakota	10.6	7.6	91.2
Trail Co., North Dakota	10.7	7.7	92.4
Subtotal - North Dakota	31.0	22.3	267.6
TOTAL - PIPELINE	230.4	164.1	1,969.2

Letter #13

Lane Council of Governments

NORTH PLAZA LEVEL PSB 125 EIGHTH AVENUE EAST EUGENE OREGON 97401 TELEPHONE (503) 687-4283

May 15, 1980

TO: Mr. Ladd Sutton

FROM: Guy Justice, Asst. Planner

SUBJECT: Extension of Review and Comment Period for the "Revised Draft Environmental Impact Statement (E.I.S.): The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System - Including Its Participation In A Hydro-Thermal Power Program"

As per our recent conversation regarding A-95 Clearinghouse review and comment of the subject document, I would like to thank you for the copies you forwarded to me. Those copies have been sent to local utilities for review and comment.

Because the Clearinghouse did not receive the subject document until May 2, 1980, review and comment can not be completed prior to L-COG's May 22 Board of Director's meeting. Clearinghouse comments will, however, be submitted to BPA following the L-COG Board of Director's June 27 meeting.

Thank you for your cooperation. If you have any questions please feel free to call.

GJ:nc/Th3

CC: Kay Wilcox, IRD
John Kiley, BPA, Portland Office

Letter #14

State Of Idaho
DIVISION OF BUDGET, POLICY PLANNING AND COORDINATION
EXECUTIVE OFFICE OF THE GOVERNOR

700 West State Street, Boise, Idaho 83720

JOHN V. EVANS
Governor

Statehouse
Boise, Idaho 83720

May 23, 1980

OFFICIAL FILE COPY
No. Date MAY 27 1980
Referred To
Action Taken
☐ ANS. ☐ NO REPLY
By Date

Office of the Administrator
U.S. Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

Dear Sir(s):

The Idaho State Clearinghouse has completed its review of your Draft Environmental Impact Statement: The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System, SAI# 00404052.

We distributed copies of the DEIS to the following agencies for their review and comment:

Idaho Public Utilities Commission
Idaho Historical Society
Idaho Office of Energy
Idaho Department of Water Resources
Idaho Department of Parks and Recreation
Idaho Department of Fish and Game
Panhandle Area Council
Clearwater Economic Development Association
Ida-Ore Regional Planning & Development Association
Region IV Development Association
Southeast Idaho Council of Governments
East-Central Idaho Planning and Development Association
Division of Budget, Policy Planning and Coordination, Natural Resources Bureau

None of the above listed agencies submitted comments to the State Clearinghouse during the review period. Please send us a copy of the Final Environmental Impact Statement when it is completed.

If you have any questions, please do not hesitate to contact us.

Sincerely,

Gloria Mabbutt

Gloria Mabbutt, Coordinator
Idaho State Clearinghouse

EQUAL OPPORTUNITY EMPLOYER

Letter #15

May 25, 1980

D. E. Zimmerman
P.O. Box 567
Davenport, Wa.
99122

Environmental Manager
Bonneville Power Administration
P.O. Box 3621
Portland, Or.
97208

Dear Sir:

After reviewing portions of the revised draft EIS and attending a local explanatory meeting, I have come to the conclusion that the fourth alternative plan would probably be the most effecient and eventually the least costly means of generation and handling power in the Pacific Northwest.

However, due to the many problems encountered in "stepping in on someone elses turf" and taking their power positions and control away from the more localized utilities, I doubt that the fourth alternative would have much of a chance of implementation, however more effecient it may prove in the future.

I therefore feel that the third alternative would be the one best suited with the best possibilities of eventually being implemented.

The actual BPA proposal seems to be very little more than the status quo, and would still allow entirely too much room for differences among the various utilities.

Alternatives one and two appear to amount to "throwing in the towel", and generally allowing things to deteriorate in any which way they will.

If the forecast power shortages are to be alleviated to any degree it will take some strong leadership by an organization that has the "muscle" to control the situation. Local, or state organizations are too small, and a nationwide level too large. The regional concept is the only logical size to deal with a regional problem.

Sincerely,

D. E. Zimmerman

Letter #16

ENERGY OUR JEWEL
ENERJOULES LIMITED
Engineering & Energy Consultant
P.O. Box 375 Mukilteo, WA 98275
(206) 353-3381

May 26, 1980

Environmental Manager
Bonneville Power Administration
P. O. Box 3621
Portland, OR., 97208

Dear Jack:

The following are comments on the Revised Draft of the BPA Role EIS as requested in the Administrator's letter of April 2, 1980.

Certainly the staff should be complimented on condensing the first draft down to this much more manageable size. Until I received this draft, I thought you may have decided to give up the whole idea as being an impossible task. It is good to see the project nearing completion.

I still maintain a basic criticism of BPA's EIS's in that they don't include consideration for the ultimate consumer. They are limited to the impact on BPA customers who don't happen to be people. After leaving BPA it has become apparent to me that Public Power really doesn't include the Public any longer. PUD's for instance have become more business oriented than public oriented. Somehow we must put the Public back into Public Power.

Probably the best case in point is Rate Design. While BPA sets the example for retail rate structures, they disclaim any connections with retail rates even though the contract requires BPA review of customer rates before implementation.

We have a national disgrace in America involving Postage Stamp or Average Pricing of energy. Through this mechanism, the low energy user is subsidizing the high energy user. Thus the low income segment of the population, in addition to facing higher energy costs, are further burdened with subsidizing the high energy user. This disgrace is generally true throughout the entire energy picture.

Graduated Rate Pricing, which reflects the actual cost of various segments of the energy supply through to the ultimate consumer, is the only fair way of pricing energy - especially in the Public sector. Furthermore, Graduated Rate Pricing, properly designed, can satisfy all the desirable segments of PURPA.

It is suggested that BPA should consider the Environmental Impacts on the ultimate consumer first. Based on such considerations, a Graduated Rate Schedule, separating the costs of hydro and thermal energy, would be appropriate at the wholesale level. Such a Graduated Rate Schedule would set the proper example for customer or retailing utilities, but more important it would give first consideration to the ultimate consumer at the rural and residential level where the major environmental impact is apparent. 1

Thank you for the opportunity to comment.

Sincerely,

Everett L. Richardson
Enerjoules Limited

Letter #17

VICTOR ATIYEH
GOVERNOR

Department of Environmental Quality

522 SOUTHWEST 5TH AVE, PORTLAND, OREGON

MAILING ADDRESS: PO BOX 1760, PORTLAND, OREGON 97207

May 22, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon 97208

Re: BPA Role EIS
April, 1980 Draft

Gentlemen:

Our partial review of the BPA Role EIS, April, 1980 draft, has uncovered a major flaw which we desire to bring to your attention directly, and without waiting for my staff to complete their review of the total document.

The document consistently addresses the air pollution impact from coal fired steam-electric generating plants, when the computations and supporting studies clearly deal only with emissions. The complicated step of modeling (using meteorological data) to go from emissions to impacts is missing. 1

See the attached May 19, 1980 memo, Bosserman to Kowalczyk, addressing this issue and other issues of lesser importance. Please have your staff contact John Kowalczyk's group: Patrick L. Hanrahan, 229-6447, for modeling, and Peter Bosserman, 229-6278, or Lloyd Kostow, 229-5186, for coal plant emissions.

Sincerely,

William H. Young
W. H. Young
Director

WHY:in
cc: Doyle/Jackman, PNRS State Review
cc: Eastern Regional Office, DEQ
cc: EPA Region X, M. Johnston through J. Herliby
AI50

STATE OF OREGON

DEPARTMENT OF ENVIRONMENTAL QUALITY INTEROFFICE MEMO

TO: J. P. Kowalczyk May 19, 1980

PLB 5/19/80

FROM: P. B. Bosserman

SUBJECT: Bonneville Role EIS, April 1980 Draft

Background

Bonneville Power Administration (BPA) has released a new, one volume version of its Role Environmental Impact Statement. The first draft was five volumes, (Parts 1, 2, Appendices A, B, C), put out for comment in 1977. The Department made substantial imputs to the first draft.

Present Draft

The April 1980 Draft is a summary type document, in which I can find few details on air quality impacts from coal-fired or biomass-fired, steam-electric plants. My review, in detail, of this new volume, will last into June, 1980. 2

Unresolved Problem

In 1978 we asked BPA for the modeling data and assumptions which their contractor used to say that the energy parks of coal-fired plants in the Mid-Columbia Region would not violate ambient air standards. I failed to acquire this data for Brian Crews to review.

Now in 1980, BPA, on page IV-43, is quoting another study saying "With respect to the National Ambient Air Quality Standards (NAAQS) no significant incremental amounts of SO_2, particulates, or NO_x are added to the background level of regional air concentrations beyond the immediate vicinity of the plant."

We should ask for the modeling data and assumptions which prove this. As a matter of fact, I have written another memo, which L. Kostow is researching, which raises a very serious concern. Another EIS, by Bonneville, "Boardman Coal Plant and Associated Transmission", March 1980, shows the Class II PSD limit, for the SO_x annual arithmetic average, of 20 ug/m^3, exceeded if the PGE-Boardman plant's allowable rather than

Letter #17 (continued)

Bonneville Role EIS,
April 1980, Draft
May 19, 1980

actual forecast emissions are modeled, along with Alumax and Boise-Cascade Wallula, projected emissions of SO_2. So far, Mostow uncovered computational flaws, which probably mean that the PSD increment is not yet exceeded.

New Problem

BPA is now listing the tons/yr emitted from coal-fired plants as impacts. They are skipping the modeling step. While this saves federal funds, it is incorrect. Could we ask BPA to wait for PGE to model Carty unit #2, as an indication of impact? Or should we ask them to retain a competent modeling consultant, who will confer with and keep P.L. Hanrahan of our staff informed of their data and assumptions? 3

Emissions are referred to as impacts on the draft EIS's pp. i, v, I-37, I-38, III-3.

Tardy Tertiaries

On page v, emissions from coal plants are treated as a local nuisance. Data from Sweden and the Adirondack Mtns. of New York indicate that groups of energy parks, consisting of coal-fired plants, emit sulfates and nitrates which can cause acid rain, visibility problems, etc. The SO_x and NO_x have converted to SO_4 and nitrates, hundreds of miles downwind. While Oregon feels secure from those effects with only one 550 MW plant going in line in the near future, as EIS contemplating many new coal plants must not ignore the later forming pollutants, while addressing the primary and secondary air pollution problems in the immediate environs of the plants. 4

Fly Ash Trace Pollutants

Fly ash from coal-fired plants is about as radioactive as brick. It is possible that the burning of large amounts of coal releases more radioactivity to the environment around the electric generating plant, than does a "nuke", if one does not include the radioactivity released during the mining, fuel processing, and waste storage of the nuclear fuel. From the standpoint of Oregon, and from the standpoint of the mid-Columbia area, and comparing Trojan to Centralia or PGE-Boardman, fly ash from coal plants will release more radioactivity to our envrironment than nuclear plants. This assumes that the uranium fuel is mined and processed elsewhere, or buried harmlessly in our environment. 5

cc: ERO
EPA-000
Doyle/Jackman
AI50.A

Letter #18

Department of Fish and Wildlife
OFFICE OF THE DIRECTOR
506 S.W. MILL STREET, P.O. BOX 3503, PORTLAND, OREGON 97208

OFFICIAL FILE COPY

May 30, 1980

Mr. Sterling Munro, Administrator
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

Dear Sterling:

The Oregon Department of Fish and Wildlife has completed its review of "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System." The current DEIS is a great improvement over the previous one. Our comments follow:

We support the concept of centralized regional coordination found under Alternatives 3 and 4, since the needs of fish and wildlife can be addressed most effectively under such an approach. We believe that minimum flows for fish must be included in any plan developed by either BPA or some future regional authority to insure the survival of upriver runs with minimal impact on power.

Page	Line		
IV-16	34-36	The installation of spillway deflectors at key Corps' dams has also had a significant impact in reducing N_2 levels during high flow years.	1
IV-16	36-38	While passing more water through turbines has reduced the N_2 supersaturation levels, it has resulted in increased losses to downstream migrants from turbine mortalities and delay.	2
IV-17	5-8	The major source of adult loss is not N_2 supersaturation. Corps-funded studies have estimated adult losses of 5-25% at each of the four lower Columbia River dams. These losses are associated with loss of migratory behavior from delay because of difficulty in finding fishway entrances.	3

Mr. Sterling Munro, Administrator
May 30, 1980
Page 2

Page	Line		
IV-17	35-38	Transportation is not regarded as a "successful measure" to protect downstream migrants from dam losses. Some limited success has been observed with steelhead, but transported spring chinook have not returned at consistently higher rates than control releases and returns are still being evaluated.	4
IV-34	38-39	We feel that the statement "Occasional bird collisions with transmission lines" does not adequately address the impacts of BPA's vast network of transmission facilities on birds.	5
IV-121	2-4	The estimated smolt mortality given here is not entirely compatible with the figures on page IV-15, lines 23-28. This inconsistency should be resolved.	6

We appreciate the opportunity to review this DEIS.

Sincerely,

John R. Donaldson, PhD
Director

cc: Columbia River Fisheries Council, Terry Holubetz
National Marine Fisheries Service
U. S. Fish and Wildlife Service

JRD:ek

Letter #19

To: A. Doyle

Intergovernmental Relations Division
155 Cottage St SE , Salem, Oregon 97310
Phone Number: 378-3732

Dept. of Environmental Quality
RECEIVED

P N R S STATE REVIEW

Project #: 8004 4 180 Return Date: MAY 23 1980

ENVIRONMENTAL IMPACT REVIEW PROCEDURES

If you cannot respond by the above return date, please call to arrange an extension at least one week prior to the review date.

ENVIRONMENTAL IMPACT REVIEW
DRAFT STATEMENT

( ) This project has no significant environmental impact.

(X) The environmental impact is adequately described.

( ) We suggest that the following points be considered in the preparation of a Final Environmental Impact Statement.

( ) No comment.

Remarks

State of Oregon
DEPARTMENT OF ENVIRONMENTAL QUALITY
RECEIVED

WATER QUALITY CONTROL

Agency ________________ By Glen Carter

4/14/80

Letter #20

DEPARTMENT OF HEALTH AND HUMAN SERVICES
PUBLIC HEALTH SERVICE
CENTER FOR DISEASE CONTROL
ATLANTA, GEORGIA 30333

June 6, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621 - SJ
Portland, Oregon 97208

Dear Sir:

We have reviewed the revised Draft Environmental Impact Statement (EIS) for "The Role of the Bonneville Power Administration (BPA) in the Pacific Northwest Power Supply System, Including Its Participation in the Hydro-Thermal Power Program." We are responding on behalf of the Public Health Service and are offering the following comments for your consideration.

In general, we have no major objections to the BPA proposal and believe that the impacts of the proposed action and its alternatives have been adequately addressed.

However, we believe BPA should continue to make efforts to develop and encourage the use of clean energy sources and systems which are essentially renewable. If it is not to BPA's benefit to make these efforts, then appropriate legislation should be enacted. Shouldn't nonrenewable energy sources such as fossil fuels be conserved for more important future needs?

We believe the development and enforcement of energy conservation measures in all levels of government need to be further emphasized. For example, home builders and residents should be encouraged to install "passive" and where applicable "active" systems in new buildings and to incorporate insulation improvements, landscaping techniques, and other energy conservation measures in
both existing and new buildings. Local and State government should be encouraged 1
to upgrade and develop building codes that would conserve the use of energy used in buildings for heating and cooling. Consideration should be given to offering lower rates for those structures determined to be energy efficient.

Incentives should be provided by BPA to promote development of small hydroelectric dams and other clean energy systems by individuals, small communities, and
private enterprise. Incentives might include rate decreases, long-term, low- 2
interest loans, and other measures.

The use of toxic and nonbiodegradable herbicides for controlling troublesome vegetative growth at power facilities and along corridors should be discouraged. More consideration should be given to mechanical, biological, and physical
control techniques. Has any thought been given to controlled grazing or other 3

Page 2 - Environmental Manager

agricultural activities? In addition, special effort should also be made by BPA to institute a hazardous materials contingency program to monitor the transport and disposal of all toxic and hazardous materials associated with its facilities.

We appreciate the opportunity to review this revised Draft EIS. Please send us one copy of the final document when it becomes available.

Sincerely yours,

Frank S. Lisella

Frank S. Lisella, Ph.D.
Chief, Environmental Affairs Group
Environmental Health Services Division
Bureau of State Services

Letter #21

United States Department of the Interior
OFFICE OF THE SECRETARY
PACIFIC NORTHWEST REGION
500 N.E. Multnomah Street, Suite 1692, Portland, Oregon 97232

June 5, 1980

ER-80/310

John E. Kiley, Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, Oregon 97208

Dear Mr. Kiley:

The Department has reviewed the revised draft environmental impact statement, The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System. The following comments are offered for your consideration.

General Comments

We commend the efforts of the Bonneville Power Administration in attempting to shorten and reorganize this revised DEIS. The revision has resulted in a more workable and understandable document.

We have noted the incorporation of many of our comments made on the
original DEIS into this document. We are still concerned, however, that 1
no mention or recognition is made of BPA's responsibilities and role as a Federal agency vitally affecting water regimens as outlined in the Fish and Wildlife Coordination Act (16 U.S.C. 661, et seq.) to include fish and wildlife as an equal consideration with other project purposes. This is most apparent in the Summary and Overview sections at the beginning of the document. Almost no mention is made of fish and wildlife resources that
have been impacted and will be impacted with the proposal and alternative 2
modes of operation. Furthermore, little mention is made here or throughout the DEIS of specific proposed mitigative or compensatory measures to alleviate potential and real impacts to these resources.

It is our view that this document still places greater emphasis on program promotion and socioeconomic information in lieu of specific and
detailed environmental (i.e., fish and wildlife) impacts. Fish and wild- 3
life impacts are frequently downplayed. You have an important role in protecting and conserving the Region's natural resources as mandated by

Federal law. This is particularly relevant to the declining fishery resources of the Columbia River system and their economic value to the Northwest economy. The document lists the present value of the commercial and sport fishery value of the Columbia River system (page
IV-15, (b) 1.a.) as exceeding 70 million dollars annually. The Na- 4
tional Marine Fisheries Service listed the annual value in 1979, with 1977 prices, as greater than 132 million dollars. As the document states, fishing has been steadily declining the last several decades, primarily as a result of hydropower activities. While this may be construed as a specific comment, it reflects the tone of the DEIS and its failure to recognize the Columbia River system fishery resources as a viable and integral part of the Pacific Northwest economy, not to mention their inestimable social and cultural values. These resources must be a primary consideration of any proposal affecting this river system.

Several short references are made throughout the document pertaining to existing and potential future low-flow augmentation for fish passage and water quality and how this may affect hydropower production. The flow recommendations developed by the Columbia Basin Fisheries
Technical Committee in 1976 are for maintenance of existing stocks 5
and not enhancement. An economic analysis of these flows, as developed by the Washington Department of Ecology, revealed that they would add from 34.4 million dollars to 59.4 million dollars annually to the Regional economy from fish and wildlife benefits, while only precluding from 13 to 15.3 million dollars annually from foregone hydropower production. We believe that a complete analysis of the economic value of the Columbia River fishing resource should be made an integral part of your program analysis in the final EIS. Included in this analysis should be a discussion on how the various program alternatives may affect the existing Indian treaty fishing rights.

We cannot comment on the environmental impacts of the alternative proposals because of a lack of detailed specific data on these alternatives in your draft. However, we believe the emphasis being placed on conservation measures has great merit and should be diligently pursued. We are disturbed that the environmental hazards of large-scale development of nuclear and fossil fuels have been treated so casually. The literature addressing this subject is voluminous and should be reviewed and addressed in the final document.

Specific Comments

Page IV-15, Impacts of the Hydro System. An analysis of the impacts
of the various alternatives on resident fish species is needed. 6

Costs and lack of available technology associated with the construc-
tion of fish passageways are listed as two limiting factors associ- 7
ated with the decline of anadromous fish species. In light of the

2

Letter #21 (continued)

high economic return and impact on the Regional economy (over 132 million dollars annually) associated with commercial and sport fishing from the Columbia River system, we do not view these reasons as a valid excuse for failure to develop effective passageways. We recognize the effort BPA has made in recent years in funding studies to alleviate these problems. The specifics and success of these studies, as well as proposed implementation of methods found to be effective should be presented in the final document.

Page IV-16, Par. 2. The coverage of Snake River runs of salmon and
steelhead under consideration for protection under the Endangered 8
Species Act of 1973, as amended, should be expanded. Causative
factors, and graphical or tabular presentation of the runs should
be included.

Mortalities associated with juvenile fish passage through the turbines 9
should be expanded upon and addressed for each alternative proposal.

Page IV-17. The ongoing efforts of several agencies in coordinating
technical day-to-day operations with BPA for fisheries consideration
are being conducted in order to prevent extinction of the resources 10
and with a view towards restoration of runs. These can be considered
mitigation measures at best and not enhancement, as the document indicates. The progress of these programs should be addressed in the final document.

It would be extremely helpful to decisionmakers if a numerical display
would be presented showing the size and status of the anadromous fish 11
runs, escapements, and catch for the Columbia River populations for all years available. These displays should include a prediction of runs with the proposal and various alternatives. Much of this data is available from National Marine Fisheries Service and Washington Department of Fisheries.

Pages IV-18 and 19. The various discussions on impacts to riparian vege-
tation and wildlife from water-level fluctuation caused by peaking power
are underplayed. The impacts do and will occur and are quantifiable. An 12
expansion on, or at least recognition of, these very real man-induced impacts should be included and addressed for all alternative modes of operation.

The coverage of endangered species existing in the area and potential
impacts is important. There may be other listed species, as well as
candidate and proposed species, in the area of influence. A complete 13
list of these species and your responsibilities under the Endangered Species Act of 1973, as amended, can be obtained from the Regional Director, U. S. Fish and Wildlife Service, Lloyd 500 Building, Suite 1692, 500 N. E. Multnomah Street, Portland, Oregon 97232. Final analysis of the potential impacts to endangered, threatened, and

candidate species of the various scenarios of power production should be reserved until fulfillment of the requirements of the Act. These should then be addressed in the final EIS.

Page IV-20 and 21, Recreation. The impact to waterfowl hunting from power
peaking and subsequent water-level fluctuations can be substantial. This 14
should be addressed in the final document.

Page IV-84. This page includes a list of impacts "attributed to transmission facilities". Impact No. 7 is "Occasional bird collisions with transmission lines", and this seems to be the total address of that impact in the entire EIS. The Department of the Interior comments of February 17, 1978 on the draft of this revised draft outlined serious concerns about transmission line impacts on waterfowl and other birds.
The statement "Occasional bird collisions" hardly addresses the magni- 15
tude of the bird strike problem, especially in areas of large populations of waterfowl. It almost leads the reader to believe that occasionally a bird may collide with a wire, and then continues its flight. Also, the electrocution of large raptors attempting to perch on power poles should be included in the list of impacts by transmission facilities.

Page IV-87, Table IV-13. This "Impact Characterization Matrix" supposedly
indicates all of the transmission system impacts. However, the impact on
"wildlife" from the operation of "Transmission Lines" is shown to be "None." 16
If one assumes that operation is the action of transmitting electricity this would be true. However, in the following section it shows a high "Visual Impact", which attributes operation to being the physical presence of the line. The matrix should therefore, show moderate (at least) impact on wildlife, as bird strikes and resulting mortalities will continue as long as the line is in operation.

Summary

We recognize the need for continued modification of power resources in the Northwest and laud your efforts in developing the various management scenarios presented in this document. As stated in our comments, both on the original and this revised DEIS, we believe greater emphasis should be placed on protection and enhancement of fish and wildlife resources as an integral part of your program. We hope that these comments, as well as our previous ones, are thoroughly reviewed and addressed in your final document. We believe that serious consideration of our comments and incorporation of them in the final EIS, as well as in your program, will result in a more complete decisionmaking package. They have been presented to you in that light.

These comments, of course, do not preclude additional and separate evaluations by the U.S. Fish and Wildlife Service, pursuant to the Fish and Wildlife Coordination Act (16 U.S.C. 661, et seq.), as construction and operational details of specific alternatives pertaining to your role in the power supply system are developed. The location of plants and transmission lines, the methods and timing of construction, and the operation of the plants can all have critical impacts on fish and wildlife resources and on their use and enjoyment.

The Department of the Interior appreciates the opportunity to comment and assist in the development of your program.

Sincerely,

Charles S. Polityka

Charles S. Polityka
Regional Environmental Officer

Attachments

Letter #22

2141 First Aven e S.
Payette, Idaho 83661
June 4, 1980

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

ATTENTION: Mr. John Kiley, Environmental Manager

Sir:

Herewith, I submit comment on DOE/EIS-0066, the Revised Draft Environmental Impact Statement: THE ROLE OF THE BONNEVILLE POWER ADMINISTRATION IN THE PACIFIC NORTHWEST POWER SUPPLY SYSTEM - U.S. Department of Energy, April 1980.

Kindly acknowledge receipt thereof.

Yours truly,

Paul Kiepe

Paul Kiepe, chairman
Nuclear Energy Subcommittee
Idaho Consumer Affairs, Inc.
Boise, Idaho

COMMENT on Revised Draft Environmental Impact Statement THE ROLL OF THE BONNEVILLE POWER ADMINISTRATION IN THE PACIFIC NORTHWEST POWER SUPPLY SYSTEM - U.S. Department of Energy, April 1980: DOE/EIS-0066

In this prolix document of 500 single-spaced pages the public once again confronts a devious, barely communicative presentation of the electric power situation in the Northwest. The natural desire of the public is to try to comprehend the situation, particularly its growth, costs, social discommotion and related aspects because of the nine additional nuclear power reactors now a-building or in the planning stages in Oregon and Washington. The bent of this EIS, like its predecessor draft using different ploys, is to snow-over the perilous, costly nuclear adventures in a blizzard of representations and discussions of circumstances and issues either quite supplementary or altogether impertinent.

Power Costs

Incredible as it may seem, the document holds off until page IV-163 (over halfway through the book) a plain statement of projected nuclear reactor electric generation costs. At IV-163 the kilowatt-hour production cost of "a privately owned (nuclear) plant in Oregon financed at 9.5% in 1995" is given as "66.4 mills/kWh." 1

This page doesn't bother to remind the reader of the probable comparative cost in that year of a kilowatt-hour from the Bonneville hydropower system. Nor does this datum

appear, as a logical organization of the EIS ought to have suggested, at page IV-119 under the sub-heading "Large Hydroelectric Generation.... Costs."

At page III-27 a protracted discussion occurs of BPA "Rates," and the circumstance is alluded to that "BPA does sell power directly to certain consumers, basically large industries and Federal agencies..." But at what rate such sales occur currently, or what hydropower rate seems likely in 1995 apparently are data too technical for revelation to the public. The reader is advised to peruse other publications, statutes, Federal standards, regulatory policies, environmental impact statements.

Nowhere in the subject publication do I find set forth the simple fact that Bonneville hydropower costs, at present, probably are on the order of 2 mills/kWh, the approximate rate at which sales are made to the "Direct-Service" industries listed at page IV-71; and that, by 1995, the pay-off meanwhile of debt likely will reduce BPA hydropower costs to not over 1 mill/kWh. 2

In plain language, the nuclear vs. hydro rates projected for 1995 are: NUCLEAR—6-2/3¢ per kilowatt-hour; HYDRO—1/10¢ per kilowatt-hour, a difference-in-cost factor of 60.

Nuclear risk

Incredible as it may seem, the subject document treats

with nuclear reactor peril in but a single sentence. At page IV-164 the two large reactors now operating (Hanford - 860,000 kilowatts; Trojan - 1,130,000 kilowatts—page IV-26) and the nine additional plants either a-building or in earlier phases (page IV-5) receive the following terse treatment: "The risk associated with accidental radiation exposure is very low."

Such humbug as this in what pretends to serve as an environmental impact statement not alone of alternative "roles" of Bonneville Power Administration but, says Summary page 1, "...addressing the impacts of the regional power supply system... as a whole," must be viewed, in the context of the Environmental Protection Act, as nothing short of misprison.

Valid risk assessment must deal, not only with the liklihood of an event's occurrence, but also, even in the event of an unlikely accident, with the severity of impact. 3

As indicated by the path of volcanic ash fallout from the Mount St. Helen's eruption of May 18, 1980 (reproduced herein as ANNEX A), a nuclear reactor melt-down accident in the Northwest, given a day of prevailing wind, could spread disease and death across 10 to 30 percent of the United States—a risk that's clearly intolerable.

How much at the mercy Idaho is of prevailing westerly

winds was made clear to everyone by the enormous deposits of volcanic ash still being dealt with, none too successfully, in eight northern Idaho counties. No reasonably aware citizen of Idaho has not, since May 18, uttered the sentiment, "How lucky we are that the fallout was not radioactive."

A typical letter-to-the editor on this topic appeared in the May 29 issue of the CENTRAL IDAHO STAR-NEWS, of McCall (reproduced here as ANNEX B). The author, Mark Seiler, happened to be visiting Moscow, Idaho when the "ash darkness" descended at 3 p.m. May 18. His companion thinks at once of the nuclear threat upwind. His letter Seiler concludes with: "God help us see through our greed. Let us find a better way to toast our bread. It's time to speak our minds... Alternative energy NOW before the clouds are no longer our friends."

BPA's "Role"

The only correct "role" of Bonneville Power Administration is to distribute, according to statutes long standing, the electric power of the Bonneville hydro system; to give priority to farm and residential users; and to accomplish these ends in a manner least environmentally threatening.

This means refusing altogether to cooperate, transmission-wise or otherwise, with Oregon and Washington entities (including Washington, D.C. entities) fooling around with the half-baked technology of nuclear power. It means discouraging the furtherance of megawatt-size applications of such technology by such refusal.

Nothing in applicable statutes requires BPA to see to it that so-called "regional electrical needs" are met. In this EIS "regional electrical needs" is code language for the insatiable lust of industrial users of energy for electric power bargains. The proper "role" of BPA is not to play whore to these yearnings. No law requires it. It's just a "role" into which a recent generation of BPA administators cast the agency, under political pressure of a disgraced national Administration, in order to star in one or another of the "scenarios" upon which this EIS lavishes its verbiage. This TV-movie approach has no place in a government document of putatively serious purpose, nor in government policy.

The "Blend" of Rates

As for the industrial contract customers of BPA who used Bonneville hydro power in surplus at the time contracts were signed, it was understood at the time of signing that an end would some to such hydro-power surplus. The term of industrial contracts was fixed accordingly. Plant

investments were amortized accordingly. So what's the present sweat about with industrial customers whose contracts soon are to run out? They simply want to break the pristine Bonneville power compacts in order to force priority-by-law customers to pay industrial power costs: "blend," that is, the 6-2/3¢ kWh rate with the 1/10¢ kWh rate by 1995, with farm and residential users picking up two-thirds of a tab increased 60-fold. It's a cheap-jack, sharp-shooters' game the U.S. government should have no part of.

The "scenario" of shifting all customer loads to a coal/nuclear base, then using the hydro "only" for peaking (with those aluminum plants snuggled up to the hydro busbars at each dam, as anyone can see who drives along the River), I consider obscene. Its appearance in DOE/EIS-0066 is nothing short of Veblenesque pornography, plainly proposing that an agency of democratic government wedded to the public commit adultery with a street-corner gang of penurious corporations who don't want to pay their own power bills.

The obscenity runs all through the 500 pages of pseudo-technical prose that plainly aim at discouraging public discovery and review.

The Final Draft

Instead of all this cockalorum, the Final Draft should re-publish Figure 11-1 of the first Draft EIS (reproduced 4
here as ANNEX C) which shows on a simplified map the eleven

nuclear power reactors the nuclear nuts went to spread across the once-elysian Northwest.

On the page opposite should appear the costs figures that appear in this commentary, comparing 1995 nuclear vs. 1995 hydro, plus a "blend" figure of the two rates and a 5
summary tabulation of users to show large industries bearing one-third of the net cost increase and lesser citizens bearing two-thirds.

Mount St. Helens Effects

Because none of the Northwest nuclear reactors, either commercial or experimental, functioning now or a-building, are "volcano hardened," it seems doubtful that the present EIS has anything like the value, however small, it had before the May 18th eruption of the still-smouldering volcano of Mount St. Helens located 40 miles east of Trojan Nuclear and 125 miles west of Hanford Nuclear, the FFTF experimental plutonium reactor on the Hanford reservation and whatever nuclear adventures still go on there.

The Hanford reservation, several hundred thousand acres of sagebrush covered now with several inches of St. Helens ash, it seems likely, must be experiencing a manifold of abrasive-dust related problems. They'll last for decades, perhaps making dangerous forms of machinery inadvisable to operate in the opinion of everybody. At the Oregon town of

Rainier, site of the Trojan reactor, there settled from an unusual east wind May 25 less than 1/4 inch of ash. It was enough, however, to raise the specter of much larger future falls as a possibility.

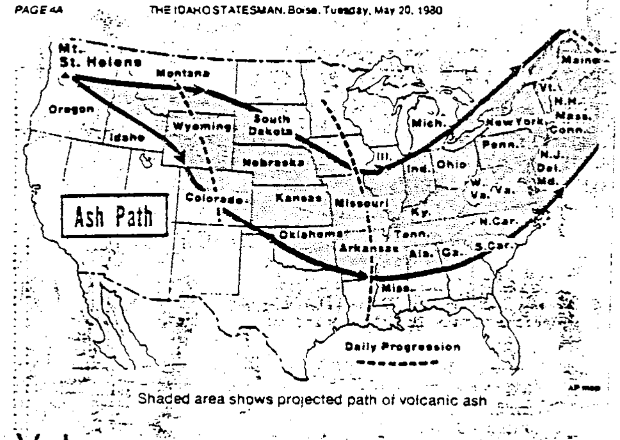
Unless very especially prepared for, it's unlikely that a functioning power reactor of Trojan size, having operated for six months with a particular core, could endure without disaster so little as a foot of ash fall. A 6
careful historical study will have to be completed to assess such factors as volcano distance, the success of air filters for machinery, etc., etc.

There's no sense recommending the Northwest nuclear program go forward, even with BPA at the helm, until an adequate volcano study occurs. With the mountain continuing to steam, smoke, growl and tremble, if the reactors were mine, I'd have shut them down two weeks ago and start now to de-fuel them and ship all fuel rods away as soon as possible. For less than ten percent of the power of the whole Oregon/Washington system, at least half of which the region could survive without at reduced though bearable living standards, it seems foolish to risk reducing to unhabitability an eastward region twice to ten times as large as the two northwestern states.

Respectfully submitted,
Paul Kiepe
PAUL KIEPE, Payette Idaho
2141 1st Avenue S/ 83661

Letter #22 (continued)

PAGE 4A THE IDAHO STATESMAN, Boise, Tuesday, May 20, 1980



Shaded area shows projected path of volcanic ash

Volcano

ANNEX A

Central Idaho Star News
Thurs. 29 '80
P. B-8

itor

Unfriendly clouds

To the editor:

Certainly everyone out there has heard about the Menacing dust clouds that hit eastern Washington and Idaho last week.

Myself and my friends were in Moscow when the lights went out. We were at a fair downtown having a great time when the cloud moved in.

Nobody thought too much about it being pitch black at three in the afternoon until all this famous choking dust starts falling. Well, everone starts running around loading up and trying to drive away.

Being too dark and dusty, driving was nearly impossible. Despite warning, we made a run for it. As the dust got thinner and it got lighter out we thanked God we made it and started wondering why there wasn't any warning. None..

Surely they knew a head of time. No matter, says a friend, just be thankful it isn't a radioactive cloud. Nuclear fallout.

Not to worry though; they would warn us, you bet. Stay inside your houses for the next 50 years! Don't go near the windows. They'll help, government rebates for deformed babies or if you get cancer before 20.

I don't treasure the thought of laying in bed listening to the rain knowing that it's deadly poison and only lead blankets will help protect those chromosomes. Buying that paper and having it say fallout in 24 states.

If you don't know what I'm talking about, find out! We owe it to our children, grandchildren and their children to stop radioactive dumping in our rivers, oceans and deserts.

God help us see through our greed. Let's find a better way to toast our bread. It's time to speak our minds.

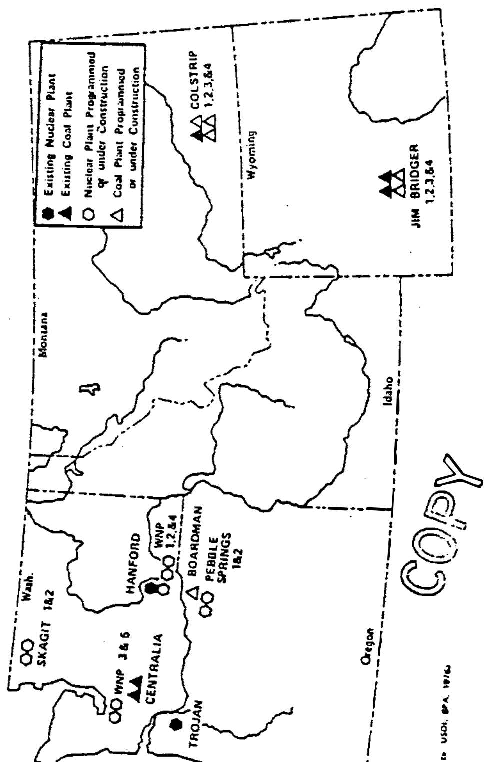
Friends, enemies, please reply to this letter.

Alternative energy NOW before the clouds are no longer our friends.

Mark Seiler

ANNEX B

Figure II-1
PNW THERMAL PLANTS
as of June 30, 1976



ANNEX C

II-20

Letter #23

Sprague, Wa 99032
6-7-1980

Environmental Manager
Bonneville Power
PO Box 3621 - SJ
Portland, Or 97208

Dear Sir:

1. The area needs an adequate supply of electrical energy for the present and for the future.
2. Conservation of energy is important and should be implemented on a continuing basis. This is good personal economics. But more importantly, it is truly the equivalent of a new energy resource.
3. Conservation alone will not do the job. The area population is growing rapidly. As these people, personally & commercially use large amounts of energy a huge shortage takes place unless we have substantial new generation.
4. We must make bold forthright moves to loosen the OPEC strangle hold on our nation. This will require a concerted effort to substitute other energy in place of oil and gas wherever possible. One example is home and commercial heating. Renewables such as solar will likely provide a portion of this need. But the goal can never be realized without substantial new blocks of electrical energy.
5. I believe the area generation and transmission facilities should be operated on the basis of a one utility concept. This would permit efficiency and also offer economic, technical + environmental advantages in the development + operation of a regional energy system.

Page 2

6. I favor alternate #3 in the revised draft EIS, which gives BPA a larger role in the area. In the event pending legislation does not become a reality, new simple legislation (few if any amendments) should be introduced giving BPA the authority to purchase energy from non-federal plants sufficient to supply the regions firm loads.

7. The preference clause must be maintained. New pseudo-utilities that are not genuine, bonafide utilities must never be granted the stamp of authenticity of becoming preference customers of BPA.

Sincerely yours,
John M Gaffney
John M Gaffney

Letter #24

UNITED STATES DEPARTMENT OF AGRICULTURE
FOREST SERVICE
P.O. Box 2417
Washington, D.C. 20013

OFFICIAL FILE COPY
JUN 11
1950
JUN 5 1980

Administrator
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

Dear Sir:

We have reviewed the Revised Draft Environmental Impact Statement on the Role of the BPA in the Pacific Northwest Power Supply System.

We feel the document should discuss research and development needs in the transmission of electricity. We are particularly concerned about (1) the need for greater transmission efficiency as a conservation measure, and (2) alternatives of underground transmission as a means of eliminating or reducing the environmental impacts of above-ground transmission. 1

Major transmission systems in the Northwest, in most cases, traverse portions of the National Forest System. Future transmission proposals can be expected to follow similar patterns and the Forest Service should be a major contributor in the planning of these systems.

Alternative three surfaces as a reasonable approach to meeting Pacific Northwest power supply needs. Cooperative planning involving the State Governors within the Region, local governments, utility and industry representatives, and the public is a particularly desirable feature of the alternative. However, we recommend that Federal land management agencies, such as the Forest Service, be specifically identified as participants in this process. 2

We appreciate the opportunity to review and comment on this Revised Draft Environmental Impact Statement.

Sincerely,

Philip L. Thornton
PHILIP L. THORNTON
Deputy Chief

Letter #25

Mueller
Rt. 2, Box 113D
Willamina, Ore. 97396

June 10, 1980

To: Environmental Manager, BPA
From: E. A. Mueller
Subject: Comments on the 4/80 draft Role EIS

1. The text and tables in Part IV comparing impacts do not reflect health and accident hazards, on the basis that these cannot be quantified. Since this is an area of major concern, a reasonable approximation permitting rough comparisons should be included if possible. A reasonably valid approximation is possible; see "Nuclear Power and Safety" (NOU 1978:35C), report of the Norwegian Nuclear Power Commission, Chapter 8, esp. Table 8.6.1 and accompanying text. 1

2. A 1000 MW coal plant emits 1-8 tons of heavy metals (mercury, lead, arsenic, etc.) each year, and some of the emitted hydrocarbons may be carcinogenic. (NOU 1978:35C, supra, pp 254-5) Shouldn't this be mentioned somewhere? 2

3. At several points in the draft, notably in the footnotes to Tables IV-37, -39 and -41, a reference back to the original draft is substituted for information necessary to understanding. The information should have been included in the current draft, and should in any event be included in the final version. 3

2.

4. In the absence of adequate information, the figures on coal and nuclear solid wastes in Tables IV-37, -39 and -41 seem inconsistent. Apparently the coal figures reflect mostly scrubber sludge, the ash being buried at the mine. The nuclear figures apparently relate to leached ore residues, and under similar "controlled mining conditions" in similar [illegible] strip mines, these also could be buried at the mine. 4

5. The assumption of a firm peaking capacity of 10% of rating for solar plants in the NW (Tables IV-32 et seq.) is questionable in view of siting limitations and the incidence of peak demand. The entire region is often blanketed by overcast or worse in winter months, for several days at a time. 10% on a cold, dark winter evening, the last of several such? No way! 5

6. The material on gaseous radioactive emissions from coal plants is sketchy and confusing, and the impact summary table entries may be improper in relation to other sources. If the 28 millicurie figures at the foot of p. IV-169 are accurate, they are either drastically incomplete as regard total emissions (and hence irrelevant) or the [illegible] [illegible] inconsistent with the footnotes 6

Letter #25 (continued)

3.

to the impact summary table. If the latter are correct, the word "None" should be omitted, since significant radioactive emissions constitute a notable environmental impact; additionally, the notation should be carried over to the "Total" column; and for fairness in comparison the footnote text should in any event indicate the fact that the nuclear plant figures reflect operations well below the "allowable releases" level.

I regret that time did not permit my having these comments typed.

Edward A. Mueller

N.B.: I'll appreciate receiving a copy of the final Role EIS when issued.

Letter #26

Wesley B Prouty
30149 Marcola Rd
Springfield, Or 97477

June 10, 1980

Environmental Manager
Bonneville Power Administration
P O Box 3621-SJ
Portland, Or 97208

Re: Revised Draft Environmental Impact Statement DOE/EIS-0066 (Apr. 1980)

Recommendation: I support the BPA Proposal as opposed to the 4 Alt.

Evaluation: The BPA Proposal will be the most cost-effective through continuation of the Northwest Power Pool concept while the BPA serves as Environmental Impact coordinator.

Wesley B Prouty

Wesley B Prouty

Letter #27

Davenport, Wa.
June 9, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon 97208

Dear Sir,

I am writing in regard to the Environmental Impact Statement.

I believe Alternative 3 is the best plan for our region. Legislation should continue to be introduced to accomplish this plan as near as possible. B.P.A. has done a good job in the past, and they should have authority to purchase power where ever possible, to meet the regions demands. The Northwest should be assured of an adequate supply of power.

I believe that the one-utility concept has many advantages in a regional power supply system.

Energy conservation should be practiced as much as possible.

Sincerely,
Don Tollefsrud
Tollefsrud
P.O. Box 472
Davenport, Wa.
99122

Letter #28

Route 1, Box 118
Davenport, WA 99122

June 10, 1980

Environmental Manager
Bonneville Power Administration
P. O. Box 3621 - SJ
Portland, Oregon 97208

Dear Sir:

My comments on the Role EIS are as follows:

I feel that we need an electrical power generating and distribution system that can meet the demand of the future. To accomplish this, I encourage and endorse Altirnative 3, as outlined in the Revised Draft of EIS. This would allow a more overall control and responsibility for generation and distribution of electrical power.

I also urge the development of adequate sources of electrical energy for the future.

With the shortage of oil related products, I am sure there will be more need for electrical energy.

Sincerely Yours,

Edward Ensor

Letter #29

June 7, 1980

Environmental Manager
Bonneville Power Administration
PO Box 3621-SJ
Portland, Oregon 97208

Dear Sir:

After attending a meeting in Davenport, WA. at which many pertinent questions were asked and answered concerning the revised Draft impact statement, my own conclusion is that the entire North West region should be somehow managed as a one-utility set up. This should maximize the possibility of the most efficient use of our entire electrical energy supply. Since B.P.A. is allready staffed with people knowledgable in the energy field it should follow naturally that they should be fully in charge of this one-utility concept.

I would endorse Alternative #3 which would give B.P.A. the power to go ahead with this plan.

Sincerely yours,
Phillip W. Krause
Creston, WA. 99117
RR Box 56

Letter #30

RE LINCOLN

LINCOLN Electric Cooperative, Inc.

P. O. Box 289 Davenport, Washington 99122 725-1141

June 10, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621 - S.J.
Portland, Oregon 97208

Dear Sir,

I appreciate the opportunity to submit comments regarding the revised draft of the Bonneville Power Administration's Environmental Impact Statement concerning the future role of BPA in the Northwest.

After reviewing the revised draft I must concur that the One-Utility concept offers environmental, economic, and technical advantages in the development and operation of a regional power supply system.

I support Alternative Three as outlined in the revised draft. It is a concept which will have the least adverse impact upon the people living in the region or the utilities providing them with electric service.

I do not believe Alternative Four would be acceptable as it certainly exceeds the intent of Congress when they passed legislation creating the Bonneville Power Administration. At that time it was recognized that there are advantages to the region for a continuance of both private and public ownership of electric utilities.

A review of the other alternatives is desireable but I much prefer that Alternative Three be the one that is implemented.

Sincerely yours,

Boyd Ressel
Manager

BR:ms

SERVING RURAL AREAS IN LINCOLN, ADAMS AND GRANT COUNTIES

Letter #31

WPPSS

Washington Public Power Supply System
A JOINT OPERATING AGENCY

P. O. Box [illegible] 3000 Geo. Washington Way Richland, Washington [illegible] Phone (509) [illegible]

June 10, 1980

Environmental Manager
Bonneville Power Administration
P. O. Box 3621 - SJ
Portland, Oregon 97202

Dear Sir:

SUBJECT: WPPSS Comments on BPA'S Revised Draft Role EIS

The Supply System has reviewed the Revised Draft EIS on "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System including its Participation in a Hydro-Thermal Power Program". The BPA Role EIS, as a programmatic impact statement, should not in our opinion, be tested against the same standards as an impact statement for a specific project. The authors should be allowed discretion in both formatting the impact statement and in bringing to the decision maker and other readers information which will promote understanding of the many interrelationships which exist in a system as complex as a regional energy supply system. It is also essential that the reader be given as clear an understanding as possible as to issues and decisions which are related to the program being discussed, but which are beyond the control of the decision maker in the selection of program alternatives. Overall we feel BPA has performed its task well.

One general observation which we have is that the authors have not attempted, and probably reasonably so, to identify a "most probable" future energy resource scenario with each alternative institutional arrangement. However, it could be explained better in the introduction to the scenario discussion, that BPA, under any of the alternatives, would not have all of the authority needed to make all of the choices of generation type, and that the reader is expected to perceive or estimate the actual environmental impacts associated with each of the alternatives. It is because this transition from alternatives to scenarios is so critical in understanding the impact statement, that we suggest the authors carefully review this aspect of the document. Some of the discussion needed to make this transition is found in Sections IV.B.3.f and IV.C; but since few readers read the table of contents before turning to the rest of a document, many may miss the relationship between the alternatives and the discussion of environmental consequences which is not encountered until after 230 pages of discussion of scenarios and present resources. 1

Environmental Manager, BPA
Page 2
June 10, 1980
WPPSS Comments on BPA's Revised Draft Role EIS

Most of our specific comments are addressed to portions of the EIS which discuss the Supply System's projects. Regional energy sources are described in Section IV.A.1. Figure IV-1 should be updated to show that WPPSS Nuclear Projects Nos. 3, 4, and 5 are all under construction. The Skagit and Pebble Springs projects are not fully licensed, and if they were indicated as under consideration, it may be possible to simplify the figure to only two categories. It would also seem appropriate to note the Washington Water Power Creston project which is, at least, under consideration. 2

In the discussion of plants under construction or presently committed to (Pages IV-27 to IV-30), the writer evidently believes that the most important descriptors of the Supply System projects are the costs and cost increases. We agree with your judgement that the cost of energy is an important element in the discussion of the regional power system. The information would be more useful if it were presented in a consistent format for all units. We therefore recommend that the mention of costs in the "description of the thermal system" be eliminated and the material in Section IV.A.1.a(3) be updated and completed for all the region's resources. At the same time, Table IV-3 and the attendant discussion should be updated (eg. Jim Bridger No. 4..."as of this writing... was scheduled to go on line December 1979" and the Skagit Project "...is in the middle stages of design"). It should be noted that the commercial operation dates for the Supply System's Nuclear Projects Nos. 1 through 5 are June 1985, January 1983, June 1986, June 1986, and June 1987, respectively. We suggest that you obtain information on the current status of the region's other thermal and hydro resources from the sponsors of the respective projects. 3

Much of the discussion in Section IV.A.1.a(2)(a)1 is a repetition of information in Table IV-3. Note that on Page IV-3 the writer used four sentences to describe and give the status of 34 hydro projects. The writer should decide what information is relevant to a counterpart description of the thermal system and then present it in tabular form for all units. We feel the important elements are included in Table IV-3. As discussed above, costs are more appropriate in Section IV.A.1.a(3) and the heat rejection system should be addressed in IV.A.1.a(2)(b)1. If you choose to leave the mention of cooling mode in IV.A.1.a(2)(a)1, you should note, for consistency, that WNP-2 has mechanical draft cooling towers.

Environmental Manager, BPA
Page 3
June 10, 1980
WPPSS Comments on BPA's Revised Draft Role EIS

The environmental impacts of thermal system are presented on Pages IV-36 through IV-48. We believe the material presented later on Pages IV-218 and Tables IV-44, 45, 46 and 47, belongs in Section IV.A.1. with the appropriate discussion of impacts of the existing and developing hydro and thermal system. We would prefer to see a single complete, consistent, and technically correct discussion of the environment impacts. Again, the writer should decide what information is important to support later conclusions. In the present discussion there is various and inconsistent mention of chemical concentrations and discharges, water consumption, land utilization, mining activities, and aesthetics. 4

The discussion (Page IV-36) of HGP is somewhat misleading, particularly where it is stated that "...State and Federal agencies...recommend off-stream cooling of the HGP heated effluent...". BPA is aware that the Washington State Department of Ecology issued its Final Determination on the Supply System's 316(a) demonstration on July 2, 1979 with the conclusion that "...(WPPSS) has demonstrated, to the satisfaction of (DOE), that the balanced indigenous population of shellfish, fish and wildlife in and on the Columbia River is protected with the existing once-through cooling system in the (HGP) and therefore, more stringent limitations on the thermal component of this discharge are not justified". That is hardly a recommendation for off-stream cooling by the agency "responsible for water quality standards". Because agencies responsible for fisheries management (principally NMFS) judged that no impact to the summer Chinook outmigrants, no matter how minimal, was acceptable, EPA objected to the proposed NPDES Permit. It is important to note, however, that EPA concurred with the DOE findings of acceptability for the period October 1 through June 30 of each year. The final permit, negotiated with BPA involvement, imposes a stringent temperature limitation of 77 F during the period of July 1 through September 7 beginning in 1983. 5

The discussion of impingement of juvenile salmonids at HGP is also misleading. The Supply System has estimated (see Page 4-21 of your reference WPPSS, 1977) that less than 1% of the juveniles passing HGP are impinged. The introductory sentence to the second paragraph of the HGP discussion (Page IV-36) is also a misinterpretation. The Supply System (Page 4-12, WPPSS, 1977) estimated the HGP discharge is fully mixed with the river at a distance three to four miles downstream. At that point, assuming average annual river flow, the temperature increase due to the heated effluent will be limited to not more than 0.3 F as compared to a normal summer diurnal variation of 4 F. The HGP discharge, as well as any heated effluent, can change the natural temperature regime for distances exceeding four miles; the problem is not to quantify the change, but to measure it. 6

Environmental Manager, BPA
Page 4
June 10, 1980
WPPSS Comments on BPA's Revised Draft Role EIS

It is stated on Page IV-39 that the combination of thermal discharges from WNP-1, -2, and -4 will change the river temperature less than 0.1 F. In fact, the bulk river temperature will be increased only about 0.01 F. Your discussion of WNP-3/5 should note that those units will dechlorinate the cooling tower blowdown. The statement concerning the HGP NPDES Permit on Page IV-46 should be updated. It appears to us that the two paragraphs on the cumulative regional impacts to water (Page IV-46) could be consolidated in one or two concise sentences. 7

The impacts of potential regional energy resources are described on Pages IV-102 through 186. Here again, the discussion suffers from inconsistency. The impacts of many of the technologies differ only in degree (eg. noise, aesthetics, effluents, etc.). It would therefore appear appropriate to consolidate much of the information in a large table which would show the relative impact of each phase: construction, operation, and decommissioning. Within each phase could be listed the subcategories of impacts. Appropriately footnoted, this table could provide the reader a comparison of the technologies. At a glance the reader could see that the cooling towers for a nuclear plant are no more "giant" (Page IV-162) than those for a geothermal plant of comparable size. It would also be apparent that any technology using a steam condensing cycle could affect local aquatic communities (Page IV-164). The table could also include construction and operation costs for all technologies projected to the same on-line date. Even better, would be the inclusion of costs for two dates, say 1970 and 1985, so the reader may judge if the utilization of generation sources other than thermal plants has been hampered by "skyrocketing costs" (Pages I-18 and IV-93). 8

Tables IV-37, IV-39, IV-42, IV-45, and IV-46 describe effluents from existing thermal plants, plants under construction, and hypothetical plants in the various scenarios considered. These tables appear to include a number of errors in interpretation that can lead the reader to erroneous conclusions. Our review of these tables has relied on: Table S-3 in 10CFR 51.20, the Final Environmental Statements prepared by the Nuclear Regulatory Commission for WNP-2, WNP-1/4, and WNP-3/5, and the discussion in the previous draft BPA Role EIS. 9

The information in these tables appears to significantly over-estimate the land required for nuclear power plants. Table S-3, the Nuclear Regulatory Commission's summary of the fuel cycle impacts, suggests that each annual fuel requirement per 1000 MWe unit has associated with it a permanent commitment of 7.1 acres. That table has another entry totalling 94 acres associated with reprocessing which is footnoted as not

Environmental Manager, BPA
Page 5
June 10, 1980
WPPSS Comments on BPA's Revised Draft Role EIS

prorated over the reprocessing facility lifetime. In our judgement the proper, while still conservative, land commitment for nuclear facilities would be the sum of the site area itself which is removed from other uses plus 94 acres per 1000 MWe, plus 7.1 acres per year per 1000 MWe. Thus, for example, on Table IV-39 a more accurate value would be 8,920 +(12.5 x 94) or 10,095 acres; plus 12.5 x 7.1 or 89 acres per year.

Water consumption clearly implies consumptive withdrawal. Based on the NRC FES the consumptive withdrawal of the WNP-3/5 project (with the Table IV-46 load factor) would be 30,000 acre-ft/year, not 133,000 as suggested in Table IV-46. Turning to the fuel cycle documentation, Table S-3 recognizes uses of 11,090,000,000 gallons per annual fuel requirement for once through cooling of the electrical generating plant supplying energy to the uranium enrichment facilities. This is not a consumptive use but has been treated as such in reaching the 133,000 acre-ft figure. Similar errors appear to have been made on the other nuclear plant projections. 10

In Table IV-39 the water emissions entry credits the nuclear fuel cycle with 333,000 tons of suspended/dissolved solids discharge per year for 12,500 MWe. This seems to flow from Table V-55 of the Draft Role EIS which, if it is to be used, should be included in the final EIS. The extraction process is the source of this value and the explanatory statement is, "Washing ore during milling produces 264,000 tons of liquid effluent that is discharged to a tailings pond. Ten percent of the effluent is assumed to be silt (suspended solids)". The pond allows the solids to settle for eventual stabilization and containment because of the possible radon discharges, but the solids carried to the pond are not a water emission. Thus, the erroneous addition of this material as a contribution to water discharges should be removed from all the tables describing nuclear facility discharges. 11

The air emissions associated with nuclear plants are generally consistent with Table S-3. It would seem appropriate to footnote the gaseous emissions and recognize that they are derived from 1974 generation fossil plants near the enrichment facilities and do not recognize changes in emission control technology that may be required of these plants by the Clean Air Act. Such technology would reduce these gaseous releases to on the order of 5% of those associated with coal units, rather than being of comparable magnitude as suggested in Table IV-42. 12

Letter #31 (continued)

Environmental Manager, BPA
Page 6
June 10, 1980
WPPSS Comments on BPA's Revised Draft Role EIS

The solid wastes credited to nuclear facilities appear to grossly overstate the actual. Table V-55 of the Draft Role EIS suggests 3.1 x 10^6 tons of solid wastes per 1000 MWe, and the values used in the tables of the Revised Draft appear consistent with that value. The previous draft EIS indicated on page V-244 that: "Overburden removed in the mining operation is the major solid waste residual and is generally used for backfilling the open pit mines". This is clearly inconsistent with the definitions used on coal units, where the solid wastes are from ash and scrubber sludges. The principal solid waste volume from the uranium fuel cycle is the tailings contribution which Table S-3 suggests is 91,000 MT per annual fuel requirement. 13

In the area of radioactive discharges, it would seem appropriate to footnote the gaseous release value with the notation that these releases are almost entirely from reprocessing facilities. Additionally, a substantially different assumption regarding liquid releases from processing seems to have been made in developing Table V-55 in the previous EIS draft than is used in Table S-3 of the NRC regulations. We would suggest the authors of this section compare the assumptions leading to the projected releases. Table S-3 suggests a lower high-level solids value and a higher low-level solids value; this too may bear your critical review. Evaluations of the radiological releases from coal fired plants are available (e.g. ORNL-5315, August 1977) and could be appropriately entered in the tables to provide a more complete picture of the relative releases. 14

In Table IV-45, we do not know the source of the 70 tons/year of solids discharged from HGP. This plant averages less than one pound per day of solids in the low volume waste stream. If the authors included the solids in the once-through cooling water, which is only changed in temperature, the same solids could be listed as discharged from hydroelectric facilities. In Tables IV-45 and -46 (and, in fact, all the tables) it should be made clear what sphere of influence is being considered. Without Table V-55 of the Draft Role EIS, it is not immediately apparent that the tabulated impacts are for the entire fuel cycle. These tables paint a different picture of the environment impacts than the discussion commencing on Page IV-36. As with our earlier comment, we believe there is merit in combining the material in a consistent manner. 15

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On Page IV-230 is commenced a 100-page discussion of possible impacts resulting from various institutional arrangements and resource mixes. While the length of the EIS has been reduced significantly, we have identified numerous additional opportunities to consolidate information and eliminate verbiage. In particular, we found the repetition in Sections IV.C and IV.D unnecessary and somewhat annoying. Reviewing (to say nothing of writing) a programmatic EIS can be tiring enough without having to read the same material, mostly verbatim, twice in a space of fifteen pages. Compare, for example, the following pages in Section IV: 231 and 283, 232-235 and 306-308, 237 and 297-298, 240-246 and 255-259. We are confident that the unnecessary repetition, including that which we have overlooked, can be eliminated in the editing for the Final EIS. The resulting product will be much more readable. 16

Thank you for the opportunity to review the Revised Draft Role EIS.

Very truly yours,

R. A. Chitwood

R. A. Chitwood, Manager
Environmental Programs Department

jh

Letter #32

INDUSTRIAL CUSTOMERS
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June 12, 1980

John E. Kiley
Environmental Manager
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208

Subject: Revised Draft Role EIS

Dear Mr. Kiley:

The Bonneville Power Administration (BPA) recently released its Revised Draft Environmental Impact Statement on the Role of BPA in the Pacific Northwest Power Supply System (Revised Draft Role EIS) for public review and comment. On behalf of BPA's Direct-Service Industrial Customers (DSIs), I would like to take this opportunity to comment on this draft of the Role EIS. Specific comments about particular portions of the Revised Draft are set out in the Attachment to this letter; our more general comments are set out below.

1. <u>The Role EIS clearly demonstrates the need for regional power legislation</u>.

The Revised Draft EIS compares five different roles that BPA could play in the regional power system. The clear conclusion of this comparison is that the alternative of new legislation similar to the regional power bill now moving through Congress is the environmentally preferable alternative. Only new regional power legislation (i) solves the federal problem of how to reallocate the limited supply of BPA power; (ii) provides a comprehensive program to develop and finance cost-effective conservation and renewable resources on a regional basis; and (iii) establishes a regional planning process to help achieve an acceptable resource mix and accommodate nonpower considerations.

2. <u>BPA's proposal -- to make maximum use of its existing authority to use the Federal Columbia River Power System (FCRPS) to serve the region's power needs -- is a second-best alternative in the absence of new regional power legislation</u>.

The "one-utility" concept that underlies BPA's proposal is a desirable and necessary objective whether or not new regional power legislation is enacted. Coordination and cooperation among

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regional power entities achieves maximum efficiency of the regional power system and minimum adverse environmental impacts. Because of its central role in the development of the regional power system and the diverse roles of other regional power entities, BPA is in a unique position to help achieve the realization of the one-utility concept. BPA must make maximum use of its existing legislative authority to provide services to integrate new and existing non-Federal resources into the FCRPS and to otherwise assist its customers to meet their power needs. Although this is only a second-best alternative, it is very much worth striving for in the absence of new regional power legislation.

3. <u>The Role EIS has important implications for BPA's allocation policy</u>.

In the absence of new legislation, BPA's role in the regional power system will largely be determined by how it allocates its fixed supply of federal power. One of the principle benefits of completing this Role EIS is that it helps define the framework of other issues surrounding the allocation process within which different possible allocation policies can be analyzed. This framework in turn has a number of implications for the development of BPA's allocation policy:

-- First, BPA should allocate power to public bodies and cooperatives to serve all types of existing loads, including former DSIs. The DSIs are existing loads and facilities, and an integral part of the regional power system and economy. 1

-- Second, the allocation policy must deal with the provision of reserves. The Revised Draft makes it clear that one of BPA's primary roles should be to provide energy and capacity reserves. For many years into the future the region will have no practical or economic alternatives but to obtain a portion of its reserves through rights to restrict what now are DSI loads. BPA's allocation policy should provide for a separate allocation of system reserve energy to former DSI loads, and insure that former DSIs receive sufficient firm power so they can continue to operate and provide system reserves.

-- Third, the allocation policy should encourage the development of sufficient new resources -- including conservation -- to meet regional loads. BPA should provide the services necessary to facilitate resource development and to integrate new resources into the FCRPS. The allocation policy should not discourage utilities (or former DSIs, if they choose to do so) from developing additional non-Federal resources.

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4. <u>The Role EIS must be sufficient to allow BPA to provide the services necessary to maintain an efficient regional power supply system.</u>

The Role EIS must be sufficient to allow BPA to undertake the provision of services (<u>i.e.</u>, load factoring, storage, load growth reserves, forced outage reserves, reserves for plant delays, transmission, wheeling, trust agency power purchases and sales, etc.) in specific instances that are consistent with its general role without first having to perform separate environmental assessments. When BPA undertakes a discrete action -- for example, the adoption of an allocation policy or rate proposal or 2
a site-specific construction program -- it must, of course, prepare an action-specific EIS. But where BPA is simply carrying out its general role, separate EISs should not be required.

For these reasons, the Revised Draft Role EIS necessarily includes a fairly extensive analysis of BPA services. While the DSIs believe that the treatment of BPA services <u>is</u> legally sufficient, BPA must be absolutely certain that <u>the</u> Final Role EIS gives BPA the legal ability to undertake the specific actions required to maintain an efficient regional power supply system. BPA should pay particular attention to the adequacy of its treatment of energy and capacity reserves, trust agency power purchases, load factoring and storage, new thermal and hydro-thermal coordination agreements, and Advance or provisional energy (see below), since these services are crucial to the ability of BPA to integrate non-Federal resources into the FCRPS and of particular customers to acquire sufficient power to meet their loads.

5. <u>The Role EIS should clearly describe the role the DSIs play in the regional power system.</u>

The DSIs play an extremely important and complex role in the regional power system. The DSIs traditionally have had an obligation to provide a large portion of the region's energy and capacity reserves; this role is unique to the Pacific Northwest and provides significant benefits to BPA's other customers. The 3
DSIs also have made possible more efficient development of the FCRPS and have provided a market for interruptible energy.

BPA should use the opportunity provided by the Role EIS to explain the role of the DSIs. This is particularly appropriate because the willingness of the DSIs to provide reserves and assist in the development and financing of new resources was a crucial part of Phase 2; the DSIs will continue to play an important role in the regional power system under new legislation or an administrative allocation.

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6. <u>The Role EIS should allow BPA to enter into new advance or provisional energy agreements with the DSIs.</u>

The Revised Draft Role EIS containing an analysis of BPA's arrangements for the delivery of advance or provisional energy to the DSIs; BPA should ensure that this analysis is sufficient to allow it to execute new advance or provisional energy agreements, should the need or opportunity arise, without having to complete 4
a separate EIS. Advance energy allows BPA to generate more power (and more revenues that reduce costs to BPA's other customers) with any given streamflow by allowing BPA to draft reservoirs below critical-rule curves in anticipation of later refill by above-critical streamflows. Advance energy does not endanger service to BPA's firm loads since it must be repaid by curtailments of DSI loads if streamflows prove to be insufficient to restore the reservoirs.

BPA also should consider whether it will permit generating resources to be used as security for the return of advance energy. Except in certain emergencies, BPA and the other relevant federal agencies traditionally have accepted as security for the 5
repayment of advance energy only an ability to curtail loads. Generating resources traditionally have <u>not</u> been accepted as security for advance energy because no <u>federal</u> agency can compel a non-Federal generating resource to be started up, and because a resource may not be capable of operating when needed. Failure to define BPA's policy with respect to advance energy could encourage the proliferation of gas turbines by utilities.

7. <u>BPA must ensure that the style and format of the Role EIS is legally sufficient.</u>

BPA has significantly modified the "building block" format used in the first draft of the Role EIS. The format of the revised draft -- which compares a specific proposal and alternatives -- requires BPA to use illustrative policies for certain elements of each alternative rather than describing the full range of possible policies. This may cause some confusion, and reduces somewhat the amount of information that can be presented.

The Council on Environmental Quality regulations contain specific suggestions about the format of EISs, including recommendations for a section that describes the alternatives <u>and</u> presents their environmental impacts in comparative form; and <u>a</u> section that discusses adverse environmental impacts that cannot be avoided, the relationship between short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and irreversible or irretrievable commitments of resources. The DSIs believe that the Revised Draft Role EIS

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satisfies both the intent and the requirements of the CEQ regulations and the National Environmental Policy Act.

* * *

Specific comments about particular portions of the Revised Draft Role EIS are set out in the Attachment to this letter. These specific comments naturally focus on the portions of the Revised Draft that most affect the DSIs and are an integral part of the DSIs views.

Thank you for the opportunity to comment on BPA's Revised Draft of the Role EIS.

Sincerely,

Lyman Harris

Lyman Harris, Chairman
DSI Executive Committee

Attachment

<u>ATTACHMENT</u>

<u>SPECIFIC COMMENTS</u>

<u>Page</u>	<u>Paragraph</u>	<u>Comments</u>	
Table of Contents		The present table of contents attempts to strike a balance in the amount of detail presented. It may be more useful to have a summary table of contents as well as a detailed outline that sets out all of the important subpoints considered in the text.	6
I-9		Bonneville should recognize as an additional guiding principle its responsibility to provide a portion of the region's energy and capacity reserves. Section 5(b) of the Bonneville Project Act provides a statutory basis for the Administration's reserve responsibilities.	7
I-10	1	The DSIs strongly support the one-utility concept and Bonneville's efforts to achieve it through new legislation or maximum use of Bonneville's existing authority. While Bonneville's proposal and its allocation policy can provide only a second-best alternative to legislation, second-best is very much worth striving for if legislation is not enacted. In defining its future role, Bonneville should attempt to maximize its service to the region and minimize deviations from the one-utility concept.	
I-10	1	The region has spawned more than 100 publicly-and cooperatively-owned utilities (compared with only 8 investor-owned utilities) because Bonneville historically has had sufficient power to meet the full power requirements of its preference customers. Without requirements contracts, the large number and small average size of individual preference utilities leaves the region largely unadopted for the difficult operating and financing effort ahead, and with far greater prospect of inter-utility combat than cooperation. Is it really reasonable to think that both the integration and tremendous diversity of the regional system can be retained when each utility, however small, must shift for itself? Isn't it more likely that after a period of disintegration, the diversity will be sharply reduced through utility mergers, consolidations or takeovers, perhaps by state power authorities?	8
I-14	5	The DSIs came to the Pacific Northwest because of the war-time need for strategic materials and because power was available in this region and not in other parts of the country closer to national markets. The DSIs did not choose direct service rather than utility service; that decision was made for them by	

Page	Para-graph	Comments	
		the Federal government, which constructed a number of the first DSI plants. The DSIs traditionally have played an important role in the regional power supply system by allowing the earlier construction and optimum sizing of generation and transmission facilities, and by providing a market for interruptible power, and energy and capacity reserves.	
I-16	3	For their part, the DSIs agreed to pay rates that included a substantial part of the total costs of the net-billed plants, even though these resources were built to serve utility load growth, not DSI load growth.	9
I-19	3	The paragraph states that the Role EIS is intended to discuss policy options, and that project- or action-specific proposals will be assessed individually as they are formulated (presumably in separate EISs). While a policy analysis certainly is useful, this approach ignores one of the principle benefits of the Role EIS: The Final Role EIS should be sufficient to allow Bonneville to provide specific services (e.g., transmission, scheduling, load factoring and storage, advance energy, reserves, and trust agency power purchases) without having to do separate EISs each time such services are requested.	10
I-20	2	BPA may or may not have to conduct a full NEPA analysis of its role in a new regional program such as Alternative 3; it depends largely upon the precise form of BPA's new legislative authority and Congressional intent with respect to specific actions under the new program. For purposes of this EIS, BPA should not assume that a full EIS necessarily would be required under new legislation. To the extent particular issues can be anticipated, however, BPA should attempt to deal thoroughly with them in its discussion of Alternative 3.	11
I-25	5	BPA's decision to consider new legislation as a separate alternative is proper and necessary to achieve the purposes that initially required the preparation of the Role EIS. Phase 2 of the Hydro-Thermal Power Program and the regional power legislation were both designed in response to changed circumstances in which BPA could no longer meet the full requirements of all its customers. Given the demise of Phase 2, the Revised Draft underscores the need for new legislation.	

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I-27	2	This paragraph should be emphasized because it clearly states the essence of BPA's proposed role: to do the best that can be done under existing authority to solve the region's power problems. In the absence of new legislation or such a clearly articulated role, there is some danger that BPA might tend to become merely a marketing agency for federal power responsible only for administering and defending its allocation policy in court. Such a reduced role, however, would leave a planning vacuum in the Northwest, with serious consequences for the region. In charting its future role, BPA should attempt to maximize its services to the region rather than to minimize its administrative burden.	12
I-28-30		The elements of the BPA proposal summarized here are discussed in detail in our comments to pages III-7 through 34.	
I-31		See comments to III-35 through 69.	
I-32-36		Alternative 3, new regional power legislation, is called "The Ranking Alternative" because it is the environmentally preferable alternative. This point and the reasons why regional power legislation is preferable should be explained in the overview section of the Role EIS. Some of the elements of the ranking alternative have been refined and perfected as the legislation has moved through Congress.	13
II-1-6	3	The description of the affected environment is accurate and concise; BPA should ensure that this short summary also satisfies CEQ regulations.	
III-1	2	The paragraph correctly states that the proposal and alternatives can be ordered to reflect the fundamental variable, the degree of BPA responsibility for regional power matters. It should be noted, however, that the building blocks that make up each alternative (which describe how BPA would operate and the resulting institutional structure) can also be ordered. The particular building block used to illustrate each alternative may not be unique to that alternative and could be replaced by other building blocks used to illustrate the other alternatives. The allocation policy associated with each alternative, for example, is for discussion purposes only and could be replaced by other allocation policies consistent with the particular level of BPA responsibility.	14

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III-1	4	The EIS properly avoids treating Phase 2 as a separate alternative. There is little possibility that Phase 2 will ever be pursued in the same form it was originally conceived. What is probable is that BPA and the region will attempt to devise a "substitute or equivalent arrangement" that attempts to achieve the "one-utility" concept that was at the heart of Phase 2. The EIS properly focuses on possible ways to achieve the objective of Phase 2 rather than focusing on the details of this abandoned program.	15
III-3-5	4	The NRDC scenario should not be treated as a distinct alternative. The EIS correctly notes that the scenario is primarily an exhortation to develop conservation and renewal resources, not a separate institutional program. Moreover, the central elements of the NRDC scenario -- the emphasis on conservation and the separate planning entity -- have been included in other alternatives.	16
III-5	5	Some of the issues considered in the Role EIS have important implications for BPA's allocation policy; these implications are discussed in the cover letter and in our specific comments to BPA's proposal that follow.	
III-8	1	BPA cannot <u>assume</u> that the current level of cooperation among <u>regional</u> power entities will continue under its proposal; rather, the purpose of the proposal is to attempt to maintain the maximum possible level of cooperation given the limitations of BPA's existing legislative authority. In the absence of new legislation authorizing BPA to acquire additional resources, BPA will have to allocate its fixed supply of federal power among the large number of applicants for that power. Any administrative allocation of federal power inevitably will result in years of litigation and conflict. Rather than cooperating to solve the region's power supply problems, regional power entities will be fighting over the BPA allocation policy. BPA's role and administrative allocation policy should attempt to minimize the extent and effects of the regional civil war over BPA's valuable power resource.	17
II-8	3	The description of customer services is written in terms of the services that would be provided to Pacific Northwest <u>utilities</u>. The Role EIS should also discuss provision of services to the DSIs and	18

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		former DSIs, to the extent such services are not provided by local utilities. Bonneville should provide services to industries on the same basis as it provides services to non-preference utilities: (i) upon request; (ii) on a non-discriminatory basis; (iii) as long as resource operation, environmental, and other restraints did not preclude services; and (iv) so long as it does not conflict with Bonneville's obligations to its preference customers.	
III-8	4	The revised draft role EIS states that "when BPA could no longer sell certain services to all applicants without decreasing the amount of energy available from federal resources (e.g., load factoring services or reserves), those services would be allocated in accordance with the preference and priority given public bodies and cooperatives by existing law, and in accordance with any applicable BPA allocation policy." This statement is an interpretation of the preference clause that may or may not be legally correct and appropriate public policy. The Bonneville Project Act requires only that the "administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives." Bonneville may be able to act consistently with this policy in providing services to non-preference customers even though such services reduce the amount of energy available to preference customers.	19
III-10		The BPA proposal includes forced outage reserves and load-growth reserves. The EIS should also discuss another important reserve Bonneville presently provides, the reserve for delay in completion or unexpected initial low output of new regional resources. The region needs this reserve and BPA can provide it in the most efficient and cost-effective manner.	20
III-10	3	The region must maintain adequate generating resources to provide a reserve for unanticipated load growth. The method by which Bonneville provides load growth reserves, however, must not give utilities an improper incentive to rely upon the reserve rather than developing adequate resources. The charge for load growth reserves must reflect the value of the reserves, not the cost of power provided or reserved, as stated in the Role EIS.	21

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III-11	2	The Role EIS should describe BPA's policy of restricting the DSIs on a pro-rata basis and assisting them in acquiring replacement power.	22
		The paragraph states that BPA is not proposing to provide long-term trust agency services for the purchase or sale of the output of new plants. BPA should consider this alternative, however, and revise the final Role EIS if appropriate.	23
III-14	4	The paragraph states that BPA would not validate the load forecasts of regional utilities unless it was necessary for the proper execution of other BPA responsibilities. This exception may be broad enough to require BPA to validate utility load forecasts as a general rule. If BPA provides a reserve for unanticipated load growth, for example, it must ensure that utilities have properly forecast their loads and are not improperly relying on BPA's reserves rather than developing adequate resources.	24
III-15	4	The DSIs strongly support the position that BPA will continue to employ its current planning assumptions, particularly planning firm hydro capability based upon critical water, using appropriate realization factors, and recognizing the need for load growth reserves equal to one-half of the region's average annual utility load growth.	
III-17	2	Although the point is made in following sections of the Revised Draft, the introduction to the description of BPA's conservation policies should make it clear that BPA will pursue "cost-effective" conservation only, not all conservation measures regardless of cost.	25
III-18	2	A better definition of "conservation" is that used in the regional power bill, which defines conservation to mean "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution." This definition distinguishes conservation from involuntary curtailments.	26
III-19	1	The proposal states that BPA will seek additional authority to conduct conservation programs beyond its present authority. The decision to seek additional authority is price worthy, but should not be part of the proposal, which by assumption was supposed to be limited to BPA's existing authority. If BPA intends	27

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		to seek new legislative authority as part of the proposal, it should go all the way and seek the comprehensive regional power legislation represented by the ranking alternative, alternative 3.	
III-19	3	Since BPA intends to treat conservation as a resource, it should make it clear that conservation will be compared to other resources and that only cost-effective measures will be pursued.	28
III-19	5	It will be very difficult to implement conservation programs through utilites in the absence of comprehensive regional power legislation. Each utility and its consumers bear the full cost of the utility's conservation program, while the benefits of the savings are spread throughout the region because of the reduced demand on the BPA system by the conserving utility.	
III-25	5	BPA should use its existing authority to the fullest extent possible to encourage the development of sufficient resources to meet regional loads and to coordinate and integrate new resources into the regional power system.	
III-30	2	As discussed above, BPA simply cannot assume that regional cooperation and coordination would continue under any form of an administrative allocation.	
III-32	1	The description of the effect of the proposal on public bodies and cooperatives is somewhat simplistic. The fact that BPA can only provide a portion of each preference customer's requirements and that such utilities will have to acquire an additional supply of non-federal power significantly changes the character and responsibility of local utilities. Under an administrative allocation, all preference customers would be responsible for generation and transmission as well as traditional distribution functions. The substantial economies of scale in utility functions could create operational and-or financial pressure for consolidation or merger of small utilities with larger ones, or into larger units. The development of this process in the context to the region's other power problems could encourage the development of state power authorities that would assume all the functions of previously independent publicly owned utilities.	29

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III-32	3	BPA has authority under existing law to continue to serve the DSIs directly. BPA may market one or more classes of power suitable for providing reserves but unsuited to normal utility operations. The administrator also has the independent right to sell power directly to a non-preference customer that would otherwise be used to serve the same load through a preference customer. Among the advantages of continued direct service, as opposed to indirect service through utilities, would be that the benefits and burdens of serving the DSI loads would continue to be distributed equitably among the preference customers as a class. The authority for and the benefits of continued direct service should be discussed in the Role EIS; they are explained in the August 13, 1979 letter and statement of the Reynolds Metal Company regarding BPA's allocation policy.	30
III-33	2	The regional civil war over the allocation of BPA power could make it difficult if not impossible to continue or extend cooperative arrangements for resource operations and mutually beneficial exchanges with other regions.	31
III-36	1	The alternative of reducing BPA's role by repealing portions of Federal Columbia River Transmission System Act that direct BPA to integrate and transmit power from non-federal facilities is unacceptable. The alternative would be extremely inefficient and result in substantially higher power costs for all electricity consumers in the region.	
III-40	2	Any allocation policy -- even one proposed for illustrative purposes only -- must recognize that BPA should allocate sufficient federal power to preference customers to serve former DSI loads. An end to direct service simply means an end to an arrangement that has been beneficial for Bonneville, the region and the DSIs. It would not give Bonneville or any utility the legal ability to treat a DSI load as if it did not already exist, or as if it were newly arrived in the Region.	32
III-43	2	The substantial environmental impacts from the loss of reserves under this alternative must be thoroughly explored.	33
III-43	3	The impediments to the development and financing of resources under this alternative would seriously	

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		exacerbate the region's present power shortage, with tremendous adverse environmental impacts.	
III-44	1	The alternative that a mutual operating agency construct and operate generating and transmission facilities, schedule delivery of power to local distribution utilities and provide all other necessary services is undesirable. Because of the special characteristics of the Federal Columbia River Power System and BPA's traditional role in regional power planning, BPA is uniquely suited to providing all services possible under its existing authority. To the extent Bonneville fails to exercise its full authority, the region moves away from the one-utility concept and unnecessarily must bear the resulting adverse environmental and economic consequences.	
III-44	4	As discussed above, BPA appears to have legal authority to provide services to non-preference customers even though such services may reduce the amount of power that can be sold to preference customers.	
III-49	5	Any arrangement to serve the DSIs through a mutual operating agency would have to be at least as attractive to the DSIs as the alternative of service through local utilities. See page III-51, paragraph 1.	
III-53	1	Alternative 3 -- regional power legislation -- is much more desirable than BPA's proposal or any of the other alternatives. New regional power legislation allows a maximum amount of coordination and cooperation by allowing Bonneville to supply the full requirements of all its customers, thereby eliminating the possibility of a regional civil war over Bonneville's valuable power resource. Legislation also establishes a new regional power planning process to fill the vacuum that would be left if Bonneville could no longer supply the full requirements of its customers.	
IV-16	1	Section states that "not all" of the adverse effects on the anadromous fishery are the result of dams and their operations. This overstates the effects of the existing power system and understates the effects of other factors in causing fishery-related problems.	34
IV-17	3	This section of the Role EIS provides a good description of the impacts of the hydro system on fisheries. There should also be some discussion of how measures taken to protect, mitigate and enhance fisheries have affected power production and operation.	35

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IV-21	4	Substantial efforts have been made to alter reservoir management and power operations to accommodate recreational activity. In some instances -- particularly restrictions on provisional energy operations -- the loss to power interests because of these mitigatory measures may far exceed the benefits to recreational users. The Role EIS should provide a framework for achieving a proper balance between power and recreational interests.	36
IV-30 --33		The description of the operation of the thermal system is very good and underscores the need for regional coordination and development of an integrated hydro-thermal power system.	
IV-32	4	The paragraph should also note that in planning the amount of resources that can be relied upon the "equivalent availabilities" must be reduced by appropriate realization adjustments.	37
IV-33 --35		The need for and benefits of a formal thermal coordination agreement are well documented in the Revised Draft Role EIS. Because of Bonneville's central role in integrating new thermal resources into the regional power system, the Role EIS should be sufficient to allow BPA to participate in the development of the thermal coordination agreement. Rather than allowing a myriad of bilateral thermal coordination agreements, Bonneville should use its central role to achieve the one-utility concept in thermal coordination.	
IV-34	4	One of the potential impacts noted in the Revised Draft is that a thermal coordination agreement might facilitate the development of thermal plants. This impact is speculative, however. The development of thermal plants will be determined primarily by regional load growth and the need for and availability of cost-effective alternative resources. The paragraph correctly points out that a thermal coordination agreement could tend to reduce the amount of total generating resources needed to serve the region's load.	
IV-3	4	The Role EIS clearly demonstrates the need for greater hydro-thermal coordination in order to maintain an efficient regional power system.	
IV-55	2	The regional power bill is needed to provide a comprehensive regional program to develop and	

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		finance all conservation measures that are cost-effective as compared to other resources. The legislation would solve the financing problem for conservation and renewable resources by enabling the entire region to stand behind the bonds for these resources. This security arrangement would also eliminate the disincentive that individual utilities face in undertaking innovative and relatively unproven methods of power supply; the so-called "pioneer's" penalties would be shared throughout the region instead of being reserved for the innovative utility and its ratepayers.	
IV-56	7	The Role EIS should make it clear that the interruptible portion of the DSI power supply directly provides a portion of BPA's load growth reserves, as well as a market for reserve energy.	38
IV-55	7	This section should note that the DSIs provide a substantial portion of the region's forced outage reserves. See pp. IV-70 through IV-76.	39
IV-58	1	The discussion of trust agency power purchases is too limited. BPA's role and policies in providing trust agency services -- particularly trust agency purchases and sales of replacement power on behalf of the DSIs -- should be analyzed in sufficient detail to allow Bonneville to enter into new trust agency arrangements consistent with its role without having to complete separate EISs.	40
IV-61	5	Alternative 3, the regional power bill, will allow the Pacific Northwest to continue to sell substantial amounts of seasonally surplus non-firm power to California to displace oil-fire generation. In the absence of new legislation, the Pacific Northwest may have no option but to use non-firm power when it is available to serve firm loads within the region.	
IV-62	3	Bonneville's policies with respect to the sale of secondary energy could affect the type of resources developed in the future. BPA might encourage the development of gas turbines, for example, if Bonneville allows utilities to firm up secondary energy with thermal resources, or if it agrees to advance energy to utilities based upon the security of the turbines.	

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Page	Para-graph	Comments	
IV-64		The table should include secondary energy sales represented by the top quartile of the DSI power supply. The top quartile of the DSI load is one of the principal markets for the sale of secondary energy; these sales have substantially reduced the costs of power to BPA's other customers.	41
IV-65	2	The description of BPA's "existing" rates should be updated to reflect BPA's current rate schedules.	42
IV-67	3	This section states that the impacts of BPA's rate increase are due to higher rate levels and not due to different rate structures. Changes in rate structures have also had substantial impact, however. Bonneville's 1979 wholesale power rates significantly altered the manner in which costs are classified between energy and capacity and shifted a disproportionate burden of the rate increase to the DSIs. The design of the availability credit provided for power restrictions has also significantly impacted the DSIs.	43
IV-69	3	The paragraph talks about the fundamental role of the DSIs in a historical sense; it should recognize that the DSIs continue to play a fundamental role in the regional power system. In addition to the benefits of the DSI loads listed in the paragraph, the DSIs have also reduced regional power costs by (i) operating at a high load factor, (ii) providing a night-time load that permits the sale of peak power during the day and the return of associated energy at night, (iii) paying system average rates despite below-average costs of service, and (iv) providing energy and capacity reserves.	44
IV-70	5	Although it is convenient to think of the DSI power supply as being divided into four quartiles, Industrial Firm power really is a single class of power with portions of each kilowatt being subject to restrictions to provide certain specified reserves. The distinction is important because Bonneville could lawfully allocate a class of system reserve energy to the DSIs that technically is capable of yielding some firm energy if it is carved up. Bonneville's authority to develop a class of industrial power in its allocation policy is discussed in greater detail in the August 13, 1979 letter and statement of the Reynolds Metals Company previously submitted as part of the allocation process.	45

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Page	Para-graph	Comments	
IV-70	7	In effect, the top quartile allows Bonneville to base its sales on average streamflows, with the DSIs providing a reserve if streamflows become critical or near-critical, as is often the case. The alternative to this energy reserve would be to build standby generation to "firm up" the energy associated with the approximately 1000 MW of capacity in the top quartile. It should also be noted that during periods when the top quartile is being served, it provides a significant all-purpose capacity reserve.	46
IV-71		The table appears to show actual power usage by the DSIs at some particular point rather than IF power contract demand.	47
IV-72	4	The point that the second quartile is considered a part of the region's firm energy load should be emphasized. The Role EIS should recognize that BPA's operating policy requres it to (i) operate the system so as to serve the bottom three quartiles of the DSI load, (ii) purchase power to serve the second quartile, (iii) preempt power to the extent Bonneville has the right to do so in order to maintain service to the second quartile, and (iv) seek curtailments prior to restricting service to the second quartile.	48
IV-72	6	The reason the third quartile reserve is not viable is <u>not</u> that the DSIs would terminate the interim agreements if it were implemented; rather, the point should be that the third quartile Phase 2 reserve was effectively nullified by the Alumax decision and cannot reasonably be construed to be part of the Interim Letter Agreements.	49
IV-73	2	Availability credits were intended to compensate the DSIs for providing the region with valuable energy and capacity reserves and for bearing the added costs of accepting service on an interruptible basis. It is not correct to say that the DSI power becomes cheaper as it becomes less reliable. The DSIs receive availability credits only if, and to the extent that power is interrupted. Since their entire power supply is interruptible under certain contingencies, the DSIs always run the risk and cost of reserve obligations, even if those reserves are not being called upon at that particular time.	50
IV-73	6	The fact that the MF contracts contain no provisions for advance energy sales makes it imperative that the	51

Letter #32 (continued)

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Page	Para-graph	Comments	
		Role EIS be sufficient to allow Bonneville to execute new provisional energy agreements, should the need and opportunity for such agreements arise.	
IV-74	2	It would be more accurate to say that BPA uses the restriction conditions of the DSI contracts to sell these reserves. The DSIs would prefer to receive service on a firm basis.	52
IV-74-76		As a general comment, the discussion of the DSI reserves would be easier to follow if the various restriction provisions were classified as energy or capacity reserves. This section perhaps could be combined with the general discussion of the DSI power sales contracts on pages IV-70 through 73.	53
IV-74	6	The DSI reserve for plant delays is available for the Phase 1 hydro and net-billed thermal plants only and subject to the termination provisions of the Interim Letter Agreements. The regional power legislation would make this a permanent reserve and extend it to all regional resources, including resources developed by investor-owned utilities for regional loads.	54
IV-75	2	The point that the second quartile (and the first quartile as well) groups the DSIs together, interrupting all on a pro-rata basis, is important. It should be made in a separate discussion of BPA's policies with respect to DSI interruptions and replacement power.	55
IV-75	5	The system stability reserve provided by BPA's right to restrict the DSIs for five minute periods should be included in the general list of DSI reserve obligations. Although technically it is a way to implement reserves rather than a reserve itself, the DSI automatic load shedding system also should be explained in greater detail.	56
IV-76	2	The statement that the basic concepts of the third quartile reserve are desirable should be clarified. What is needed is a reserve for regional resources -- whether they are built through Federal participation, by preference customers as non-Federal resources, or by the region's investor-owned utilities. This reserve need not take the form of the third quartile reserve in the Phase 2 arrangement.	57

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Page	Para-graph	Comments	
IV-76	3-5	The discussion of the benefits of the high load factor DSI loads is good, but perhaps could be expanded. The ability of BPA to accept the return of energy at night-time largely is dependent upon the DSI loads, for example, and makes possible the peak-energy exchange agreements with California utilities that provide substantial additional amounts of firm energy to the Federal system. The importance of the DSIs in maintaining minimum streamflows to protect nonpower uses also should be described.	58
IV-76 --78		The discussion of Advance Energy should be sufficient to allow Bonneville to execute new Advance or provisional energy agreements, should the need or opportunity arise.	
		The section should describe more fully the benefits to Bonneville and its customers of making Advance Energy available to the DSIs. The sale of Advance Energy permits more energy to be generated for any given level of streamflow by reducing spilling (Advance Energy allowe reservoirs to be drawn down below critical rule curves in anticipation of later refill by above-critical streamflows). This reduces rates to Bonneville's other customers by spreading Bonneville's total costs over more kwh of sales. The provision of Advance Energy does not endanger service to firm loads since it must be "repaid," if streamflows are insufficient to refill the reservors.	59
		The section also should describe the security for Advance Energy. Except in certain emergencies, Bonneville and the other relevant federal agencies have accepted as security for the repayment of advance energy only the ability to curtail loads controlled by Bonneville. Generating resources traditionally have not been accepted as security for advance energy because no federal agency can compel a utility to start up a non-Federal generating resource. The potential inability or unwillingness of a utility to operate a non-Federal generating resource to repay Advance Energy could jeopardize service to Bonneville's firm loads.	
IV-78	3	The environmental impacts associated with Advance Energy should be compared to the impacts of not making Advance Energy available (<u>i.e.</u>, of not operating below the critical rule curve), including additional spills and the need for more total generating resources	60

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Page	Para-graph	Comments	
		to serve the same amount of total load. Some of the impacts noted in the Role EIS -- in particular, adverse impacts on sport fishing resulting from changes in river flows and temperature, inhibited migration of anadromous fish due to temperature changes, and increased fish mortality due to passage through turbines--are questionable because Advance Energy results in more even streamflow (with reduced temperature changes) and reduces spills (with less danger of nitrogen supersaturation).	
IV-79	1	It should be emphasized that DSI loads are not growing and are served by resources already in existence. The need for new resources and the associated environmental impacts are caused by <u>utility</u> load growth.	61
IV-79	2	The comparison of the DSI load to the generating plants required to serve it is misleading. As the Role EIS points out, the second quartile of IP power is nonfirm and provides a reserve for plant delays; in the absence of this reserve, the region would need approximately 770 MW of additional standby generation. None of the DSI capacity if firm.	62
IV-80	4	The list of economic impacts of the DSIs should be updated to reflect the most current information available.	63
IV-81	2	The conclusion that the DSIs have a "significant impact" on the region's physical environment is somewhat puzzling in view of the specific analysis in the following sections, which note DSI plants are in compliance with air quality standards, emit a relatively small portion of areawide air pollution, contribute no discharge or negligible amounts to existing water quality problems, have a negligible impact on the surrounding terrestrial environment, generally do not threaten endangered species and are meeting health standards. While the DSIs include important "heavy industries," the environmental impacts from DSI activities generally are considerably less than the impacts from other types of industrial activity.	64

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Page	Para-graph	Comments	
IV-94	3	The paragraph correctly notes that new legislation would be required to allow preference utilities to achieve the benefits of being able to back up financial arrangements for new resources with the equity represented in their investment in the FCRPS. Although cooperative financing would provide a second-best method of financing, it cannot provide the same spreading of risks and costs as can be achieved under new legislation.	
IV-97	5	In the absence of new legislation that gives the Northwest the tools it needs to restore a firm load -- firm resource balance, the region may not be able to continue to supply substantial amounts of seasonally surplus, non-firm power to the Pacific Southwest. In addition, the solution to the regional battle over BPA allocations and the maintenance of the one-utility concept is a practical prerequisite to the continuation and extension of mutually beneficial inter-regional power transactions.	
IV-99		The Role EIS should carefully consider the impacts of the failure to develop sufficient resources. The DSIs strongly believe that the adverse impacts of having insufficient resources significantly outweigh the impacts of resource surpluses.	65
IV-99	4	Excessive reliance on the possibility of imports from other regions could undercut national energy policy since much of the surplus generating capacity that might be available probably would be oil-fired generation. It should also be noted that if the Northwest cannot obtain sufficient power from outside the region, it may have no option but to operate the hydro system in a manner that seriously harms fish and wildlife and other non-power uses.	66
IV-99	7	The conclusion of this paragraph should be emphasized: if the Northwest cannot develop sufficient base-load generation, it may have no choice but to develop gas turbines and other resources with short lead times, even though these resources are inconsistent with national energy policy and environmental considerations.	67
IV-100	4	BPA's comparison of the impacts of resource surpluses against the impacts of insufficient resources clearly indicates that a power surplus is the lesser of the two evils.	

Letter #32 (continued)

Page	Para-graph	Comments	
IV-103	2	The analysis of the potential energy savings from conservation assumes a "best-case" analysis in which 100% of the population adopts 100% of the suggested actions. (It is interesting to note that in describing the impacts from generating resources the Role EIS assumes a "worst-case" analysis.) The Role EIS should include some estimate of the realistic actual expectation of conservation savings. An imprecise estimate is better than a precise estimate that is irrelevant.	68
IV-105	5	It is important to note that the total potential energy savings from the conservation actions described on the preceeding pages are not additive. Insulating hot water heaters and lowering lighting, for example, may increase requirements for space heating.	69
IV-112	3	It is important to note that some load management techniques may be counterproductive if they reduce peak loads only by requiring the consumption of more total energy during off-peak periods.	70
IV-112	5	The DSIs presently provide a substantial off-peak load which significantly reduces streamflow fluctuations. As BPA noted in its determination order regarding the Public Utility Regulatory Policies Act ratemaking standards, the restrictions rights provided by the existing DSI contracts represent a very significant load management technique.	
IV-119 --186		The description of the environmental impacts of various generating resources set out in these pages of the Draft Role EIS is very good; it sets out the necessary information in a clear and concise manner.	
IV-187 --229		BPA's "worst-case" analysis of possible resource scenarios is interesting and provides useful information about extreme resource mixes. It would be helpful, however, if BPA would also use the material developed in its discussion of the existing and future regional power system to describe the probable resource scenario.	71
IV-233	2	The fact that the size of DSI loads are limited by their BPA contracts gives the DSIs a very strong incentive to improve production efficiency. The only way the DSIs can increase production is by making more efficient use of the energy to which they are entitled. Technological improvements in the aluminum	

Page	Para-graph	Comments	
		industry require large capital investments, and these investments are recouped through the increased production that the improvements make possible; they cannot be made if electricity consumption is simply reduced and production levels frozen.	
IV-233	5	The summary description in the Revised Draft Role EIS understates the serious impacts that would result if the DSIs were not able to obtain electric power in a manner and at a price that would allow continued economic operations in the region.	72
IV-234	3	The statement that "environmentally, the impacts of the DSI's decision to close down would be positive for the region" is very misleading. The discussion on pages IV-81 and 82 of the specific environmental impacts associated with DSI plants indicates that the DSIs have a small or negligible impact on the physical environment. The DSIs almost certainly would have less adverse environmental impacts than an equivalent load of other types of industries.	73
IV-235	3	The paragraph states that BPA's 1979 rate proposal incorporates the proper price signal that future energy costs will increase at a much faster rate than future capacity costs, and may therefore encourage the conservation of energy. This is incorrect. The BPA rate proposal made improper adjustments from the cost of providing service that shifted costs from capacity to energy. These adjustments shifted more of BPA's total costs to its DSI customers and less of BPA's costs to its preference customers. Since the DSIs appear to have a less elastic demand than the consumers of preference utilities, BPA's wholesale rate structure may actually have had the perverse effect of encouraging retail consumers who are responsible for BPA's load growth to consume more electricity than they would have consumed had BPA's rates accurately reflected the cost each customer classification actually imposes on the system.	74
IV-235	4	The paragraph states that BPA is investigating the feasibility of conservation rate incentives for aluminum companies that would tie the rate charged to the amount of alumunim produced per unit of energy consumed. The statement is puzzling since BPA emphatically rejected this proposal in its December 1979 determination order regarding the ratemaking standards established by the Public Utility Regulatory Policies Act.	75

Page	Para-graph	Comments	
IV-237	4	BPA suggests both that utilities might overbuild and that they might underbuild if they independently must build additional non-federal resources. This conclusion is puzzling, but accurate. There is a risk of underbuilding because it would be significantly more difficult for individual utilities to develop and finance resources. There is also a risk of over-building, however, because resources generally can only be added in blocks larger than most individual utilities and because utilities have to provide a greater portion of their own reserves and services. It is not clear how these two potential risks will work out; what is clear is that the region almost certainly will not be able to develop the appropriate amount and mix of resources in the absence of new legislation.	76
IV-239	2&3	It is extremely important that Bonneville define its policy with respect to providing nonfirm power for use in combination with gas turbines to serve firm loads; gas turbines soon may become a common power resource in the Northwest and the opportunity to define a policy will be lost. As part of this policy BPA should consider distinguishing between gas turbines used to back up service to an interruptible load itself and turbines used to back up service to any type of firm utility load that a utility attempts to serve primarily with federal secondary or other class of nonfirm power.	77
IV-239	4	BPA must ensure that the treatment of customer-owned resources in its allocation policy does not discourage preference utilities (or DSIs and former DSIs, if they choose to do so) from developing needed new resources.	78
VI-240	3	The Revised Draft fails to consider the possibility of long-term trust agency agreements on the grounds that BPA's customers have not requested BPA to act as a trust agent. Even if this reflects the present political situation, the situation may change in the future. Moreover, the offer to act as a trust agent was an important part of Phase 2, and should be considered by BPA in the Role EIS.	79
IV-242	2	A preference customer presumably would be able to continue to draw power off the regional grid even if it failed to develop an adequate supply of non-federal power to meet the portion of its requirements	

Page	Para-graph	Comments	
		not met by its BPA allocation (preference customers would have priority on secondary energy and it is technologically impossible to limit physically each utility's actual use of federal power because of the interconnected grid). In periods of above-critical streamflows, preference customers that fail to plan for and develop adequate non-federal power supplies would receive more federal power (using more secondary energy that otherwise would reduce the rates of all preference customers) and perhaps pay lower total power costs than other preference customers who properly planned for non-federal resources. In periods when streamflows are critical, preference customers with inadequate supplies of non-federal power would continue to draw off the grid, turning the planning shortage on their system into an operating shortage in the entire region. This "free rider" problem -- where some preference customers gamble on the availability of secondary energy and rely on other preference customers to develop non-federal resources -- could lead to a disintegration of the high degree of coordination and cooperation among the region's utilities, with serious operational and environmental consequences.	
IV-243	2	The conclusion in this paragraph is central to the Role EIS and should be given much greater empahsis: "It can be said with some certainty, however, that if BPA did not provide services with the flexible resources of the FCRPS that more resources, both generation and transmission, would be required by the region not only to replace FCRPS resources, but to offset diversity savings lost due to reduced system coordination."	80
IV-243	3	As a legal and policy matter, BPA should not refuse to provide services to specific types of resources.	
IV-244	4	This EIS should be sufficient to allow BPA to provide services to other resources, as well as to WPPSS 4 & 5, without having to do separate EISs (except for site-specific construction impacts).	81
IV-246	3	The Revised Draft notes in separate places that the provision of services by BPA may encourage the development of both conventional and alternative generation. It should also note that as between the two resource types, the failure to provide services may inhibit the development of alternative generation	82

Letter #32 (continued)

Page	Para-graph	Comments	
		more than it inhibits the development of conventional generation.	
IV-255 --259		This section is similar to pages IV-240 through 245; please see the comments to that prior section.	
IV-262	3&4	The Role EIS clearly indicates the serious adverse environmental impacts that would result from loss or reduction of DSI reserves. BPA must make every effort to insure that the DSIs can continue to provide a portion of the region's power system reserves.	
IV-262	5	The paragraph states that the overall need for generating resources would be substantially reduced if the DSIs were not served by the regional power system. Over one-half of the DSI power supply is nonfirm power, however, that is not suitable for normal utility loads. The remaining two quartiles of firm DSI energy -- approximately 1700 MW -- is equivalent to slightly more than two years of normal regional load growth. None of the DSI capacities is firm. The effect of the DSIs ceasing operations would simply be to postpone for a brief period the development of additional resources that the region needs to serve utility load growth.	83
IV-267	1	The Role DEIS contains useful data about the extent and impacts of secondary sales outside the region; this data should be updated and included in the Final EIS.	84
IV-268	3	The problems associated with energy imports underscores the need to develop adequate baseload generation and to maintain sufficient night-time load to allow the delivery of energy during off-peak periods.	
IV-269	4	The paragraph states that energy surpluses could result from overbuilding. While overbuilding obviously could cause surpluses, power for export primarily comes from seasonally surplus nonfirm energy in excess of the region's needs during periods of above-critical steamflows. The region's present load-resource balance suggests that overbuilding is not likely to be a problem for many years in the future.	85
IV-270	3	As noted above, the discussion of exports should focus on surplus energy during above-critical streamflows, not on overbuilding.	

Page	Para-graph	Comments	
IV-271	1	The ability to execute mutually beneficial interregional exchanges largely depends upon the Northwest having a sufficient load during off-peak periods to allow the return of energy consistent with streamflow constraints.	
IV-271	2	The paragraph states that more expensive thermal resources would be displaced by cheaper hydro only if the savings in operating costs exceeded the fixed costs of idle plant capacity. This is incorrect. By definition, fixed costs will be incurred whether or not the plants are operating. Thermal plants will be displaced whenever the savings in variable costs (variable costs of thermal generation minus the rate for hydro) exceed the costs of idling the thermal plants. The economic incentives to idle thermal plants when hydro secondary is available underscores the need for BPA rate schedules that encourage utilities to continue to operate thermal plants to displace even higher cost petroleum-fired generation outside the region.	86
IV-273	2	By giving the region the tools it needs to restore a firm load-firm resource balance again, new legislation allows the Pacific Northwest to continue to sell substantial amounts of seasonally surplus nonfirm power to the Pacific Southwest to displace oil- and gas-fired generation. Because it is the only way to prevent a civil war within the Northwest over allocations of BPA power, the regional power legislation is also a practical prerequisite to continuation and extension of mutually beneficial power arrangements between the regions.	
IV-277	3	The paragraph implies that the failure to serve the DSI load would have a beneficial effect on nonpower demands for water. This is incorrect. The hydropower that would become available because of the loss of the DSI load presumably would be used to serve other types of loads. These other loads almost certainly would not have the same high load factor and interruption rights that make the DSIs so important to maintaining minimum streamflows and accommodating nonpower considerations. The loss of the DSI loads and substitution of other loads would have a substantial adverse impact on nonpower river uses.	87
IV-277	4	Accommodation of nonpower considerations largely depends upon developing sufficient new generation to allow flexibility in river operations.	

Page	Para-graph	Comments	
IV-281	5	The suggestion that continued direct service of the DSIs under regional power legislation reduces the prospects for accommodating power and nonpower considerations is incorrect. In the absence of legislation, the DSIs would seek service from local utilities. Since 85% of the DSI load is located within or adjacent to the service territories of existing preference customers and would be eligible for an allocation of federal power, the DSIs would continue to be a load on the FCRPS, even though they would be served indirectly through local utilities. Furthermore, as discussed above, other loads with less desirable load characteristics almost certainly would replace the DSIs to the extent the DSIs do not continue to be loads on the FCRPS.	88
IV-297 --302		This section on BPA allocations should be updated to reflect BPA's proposed allocation policy. Thre is no reason to assume that BPA would adopt different allocation policies under different alternative roles. The assumption of different allocation policies is confusing, in spite of BPA's statement that the different policies are for illustrative purposes only.	89
IV-297	6	See comments to Page IV-237, paragraphs 4 and 5.	
IV-299	1	If BPA adopts the alternative of a single fixed allocation of Federal power to existing preference customers, it must recognize that former DSIs within or adjacent to existing preference cuetomers are included in these preference customers' loads eligible for an allocation.	90
IV-300	4	If BPA allocates power to new and existing preference customers, it must recognize that the DSIs are existing regional loads eligible for an allocation of BPA power.	91
IV-305	5	While the paragraph recognizes that the aggressive conservation program under the regional power bill could offset the price effects of lower rates, it concludes that reduced rates for residential consumers under the regional power bill could increase their consumption of electricity. The paragraph should explain that the regional power bill is intended to achieve all cost-effective conservation that would result if electricity was priced at the full incremental cost of new resources. Even though	92

Page	Para-graph	Comments
		rates will be lower, the regional power bill will result in much more total conservation than if there is no bill.
IV-306 --308		This section is similar to pages IV-232 through IV-235; please see the comments to those pages.
IV-313 --331		This section provides a very good and concise summary and comparison of the proposal and alternatives. The comparison makes it clear that new regional power legislation expanding BPA's authority is the environmentally preferable alternative. Only new regional power legislation (i) solves the federal problem of how to reallocate the limited supply of BPA power; (ii) provides a comprehensive program to develop and finance cost-effective conservation and renewable resources on a regional basis; and (iii) establishes a regional planning process to help achieve an acceptable resource mix and accommodate nonpower considerations.
		BPA's proposal is the second-best alternative in the absence of new legislation. The "one-utility" concept is very much worth striving for and BPA should use its existing authority to the fullest extent to achieve that objective.

Letter #33

P.O. Box 348
Davenport, Wa. 99122

June 9, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon, 97208

Dear Sir:

As one interested in the continued availability of Pacific Northwest Power, my feelings regarding the revised Environmental Impact Statement are:

1. We, homeowners and industry, seek assurance that adequate power at the lowest cost will be available in the future.
2. The Conservation of all types of energy must be encouraged.
3. The preference clause, as used in the past, must be continued. Many Cooperative Utilities depend upon it for their existence.
4. I endorse "Alternate 3" as outlined in the Revised Draft of E.I.S.

B.P.A. by their past experience and efficient operation have earned greater responsibilities. Our area needs their expanded activities in distribution of electric power. To divide these responsibilities among several agencies or utilities would create inefficiency, thus, higher prices and inferior service to us as homeowners and to industry as well.

The future existence and continued development of our Pacific Northwest depend on these issues. I endorse their adoption.

Sincerely,

Frank L. Campbell

Letter #34

GAFFCO FARMS, INC.
Route 1, Box 75 Sprague, Wash. 99032

F. LEONARD GAFFNEY, PRESIDENT
REGINA I. GAFFNEY, SECRETARY

June 10, 1980

Environmental Manager
Bonneville Power Administration
PO Box 3621-SJ Portland, Oregon 97208

Dear Sir,

I am writing with respect to the revised draft Environmental Impact Statement. My concern like that of many others is to continue to grow and enjoy the energy without significant environmental stress.

With respect to the future I support the "one utility concept" for the regions generation and transmission of power. I support alternative 3 as outlined in the revised draft EIS, giving BPA an increased role in the region.

I support the preference clause and believe a continuing emphasis on conservation is vital to the region.

Yours truly,
F Leonard Gaffney

Letter #35

STATE OF WASHINGTON
Dixy Lee Ray
Governor

DEPARTMENT OF GAME
600 North Capitol Way, GJ-11 Olympia, WA 98504 206/753-5700

June 11, 1980

John E. Kiley, Environmental Manager
Bonneville Power Administration
P.O. Box 3621 - SJ
Portland, Oregon 97208

REVISED DRAFT ENVIRONMENTAL IMPACT STATEMENT:

The Role of The Bonneville Power Administration in the Pacific Northwest Power Supply System, U.S. Department of Energy, April 1980

Dear Mr. Kiley:

Your document has been reviewed by our staff as requested. Three general concerns of major importance are listed below.

1. We acknowledge that this revised edition conforms to CEQ guidelines, but our review of fish and wildlife impacts are complicated by the random placement and interspersion of impact evaluations. The addition and incorporation of many of our comments made on the original EIS document have been noted in the Role EIS. However, we are still concerned with the unequal consideration being given to fish and wildlife in relation to other hydro project concerns. Little mention is made, except under items termed "Conservation Impacts", of specific or proposed mitigative/compensatory measures to alleviate potential and real impacts to fish and wildlife resources. 1
2. It is our view that this document still places greater emphasis on power programs, proposal promotion and socio-economic information regardless of specific and documented environmental impacts. Proposals that impact fish and wildlife are presented as a matter of fact consequence to be accepted in regard to hydroelectric generation. There seems to be a serious lack of accepting responsibility in protecting and conserving our fish and wildlife resources as mandated by Fish and Wildlife Coordination Act. This is particularly apparent when mitigative measures are not presented in either the proposal or alternatives. 2
3. We strongly oppose the expanded use of the F.C.R.P.S. for generation of "peaking power" due to its deleterious impacts on wildlife and anadromous fisheries of the Columbia and Snake river systems. Only active pursuit of reducing the turbine hydro flow of power peaking through regional conservation methods in conjunction with increased spilling at appropriate migrating periods can possibly diminish these impacts. 3

Page 2
June 11, 1980

Listed below are specific comments referenced by page and sentence number.

Operation of the Hydrosystem

Page IV 3-8

"Impacts of operating hydropower resources must be evaluated with respect to both daily and seasonal characteristics. Within each time frame, both energy production and capacity (peaking) production must be considered to describe the full spectrum of operation effects associated with changes to the configuration of the hydropower system." 4

To describe the full spectrum of operational effects it is necessary to include deleterious impacts to anadromous fish migration, riparian vegetation, wildlife, pleasure boating, hunting, fishing and other recreational uses of the hydro resource. The organizational premise of your document precludes equal consideration of these resources.

IV 17 4-5

The problem of spillway supersaturation is not the major problem affecting anadromous fish. Low flow levels in fishways with additional losses of adults not migrating upstream beyond reservoir areas comprise the largest percentage of adult mortality. Juvenile mortality from turbine generation occurs at 15-30% for each mainstream dam. 5

IV 17 19-20

What mitigation measures are you referring to? 6

IV 17 21-30

It is obvious that the listed agencies are assuming the responsibility for supporting a dwindling, non-productive fisheries resource. Since this condition is a result of large scale hydroelectric generation and since BPA is responsible for power generation and energy forcasting, BPA should also assume the responsibility for mitigation of the unacceptable conditions. As we understand, the U.S. Army Corps of Engineers, under the Fish and Wildlife Coordination Act, presently and in the past has been responsible for mitigation and compensation, both monetary and real, for fish and wildlife losses that have resulted directly and indirectly from BPA proposals. Considering that BPA would be one of the foremost in economic and financial gains, could it not be asked that BPA itself provide mitigation and compensation for environmental damages? We realize that in the past, BPA has conducted or participated in environmental studies. However, it must be understood that unless "replacement" lands or wildlife enhancement programs are not extensively provided for, no amount of studies will maintain the natural resources of the Pacific Northwest. 7

IV 17 31-37

Your documentation of the more successful protective measures is not completely accurate. The most recent attempt to bypass hydroelectric obstacles via 8

Letter #35 (continued)

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June 11, 1980

IV 17 31-37 (continued)

transportation either by trucking or barging salmon smolts to the Columbia River estuary have not produced an increase in the already low (1-2%) return of adults to upstream hatcheries. Secondly, turbine bypass systems have not been successful unless bypass flow rates exceed turbine flow in both speed and quantity.

IV 17 38-39

"Manipulation of storage reservoirs and individual dams to provide flow and spill conditions that enhance juvenile migration" could be considered mitigation if the spill conditions coincided with spring to summer migration periods. 9

IV 20 13-17

Additional turbines at FCRPS and mid-Columbia PUD projects would increase already unacceptable juvenile mortality rates. 10

IV 22

"Peaking unit additions to the FCRPS and Mid-Columbia public agency projects would result in greater and more rapid fluctuations in flows and reservoir levels."

These fluctuations would further negatively impact riparian vegetation by creating unstable water levels both above and below dams. These impacts are presented in a manner which tends to minimize the importance of wildlife losses. 11

IV 25-50

The proposed increase in the number of hydrothermal generating plants using nuclear or coal fired steam in coordinating base loads and load fluctuation demands is disturbing. Numerous studies have been done documenting the hazardous environmental consequences. Even without worst case condition normal operation of these facilities places the burden of meeting peak loads on those hydrosystems capable of rapidly altering energy output. This would mean additional deleterious impacts could be expected from the coordination of hydrogeneration and thermal gneration facilities. 12

IV 51

Emphasis on conservation should be of highest priority. It is imperative that you include it. The policy of conservation should be diligently pursued.

IV 78

Environmental impacts associated with advanced energy sales to Direct Service Industries (DSI) are related to reservoir drawdown, decreased desirability of sports fisheries, and deleterious impacts to anadromous fish from increased temperature and turbine flow. These impacts occur any time a reservoir is drawn down. 13

Page 4
June 11, 1980

IV 81

Without the names and types of DSI involved, their impacts are impossible to assess. Evaluation cannot be completed without accurate information. Please include more information on the individual nature of DSI manufacturing plants and their location to expedite review of their impacts 14

IV 88

We are not sure of the impacts of increased energy fields on wildlife; however, certain adverse effects have been noted in studies on dairy cows raised under transmission lines. 15

IV 92 6-7

We will continue to review and provide comment on potential environmental impacts resulting from future energy projects under SEPA and NEPA guidelines.

IV 93 38-45

We appreciate your consideration of non-power hydrosystem uses. Considering the large scale impact on natural resources, it would be appropriate to evaluate impacts of power generation on these resources in sections separate from conflicting non-power use consideration. 16

IV 99

Load resource imbalances would put additional strain on fish and wildlife habitat, the extent of which can only be presumed worst case since official data are not available in the scenario. 17

IV 100

Impacts of Resource Surplus "The Pacific Northwest would bear the impacts of operating the facilities, but the revenue from the sale of export power would mitigate the cost impact."

Once again the serious problem of "operating" impacts is glossed over. Of course, the Pacific Northwest would bear the irretrievable loss of depleted fish runs and wildlife habitat, but at what cost?. Unless the proposed "revenue" from the sale of export power is used to reestablish viable anadromous fish runs and protect impacted wildlife habitat areas, it is misleading, even incorrect, to state that revenues would mitigate the operational effects. 18

IV 101 15-24

There is an obvious contradiction in qualifying non-power consideration with respect to "relative priorities" given the ability of the region to meet its electrical load requirements. 19

Page 5
June 11, 1980

IV 101 15-24 (continued)

To qualify non-power uses in this subjective manner denies the important contribution of these resources to the Northwest environment. Wildlife considerations are not listed under non-power issues. The format of Future Power System Development needs to be rewritten to include greater emphasis on wildlife impacts and economic importance of fish and wildlife. 20

IV 108

The conservation environmental impacts are appropriately assumed. In the broadest sense the less energy we use, the less severe the eovironmental consequences will be. By reducing the need for electrical generation, environmental degradation can be minimized.

Power-Non-power Conflicts

IV 274

The mentioned concerns involving these conflicts are commendable, but there is obvious underestimation and downplay of impacts of large scale hydroelectric generation on fish and wildlife. "...Fish, wildlife, wild and scenic river preservation -- may be severely impacted by the construction and operation of such projects. Some resources such as wetlands may be impacted simply by changes in water levels and flow patterns." Conditional phrasing ("may be impacted") is unnecessary. Our contention is the degree to which they would occur. Fish and wildlife impacts would and do occur from hydroelectric generation and wetland environments are seriously impacted from fluctuation of water levels and flow patterns. The concomitant loss of dependent wildlife is of obvious concern to our Department. 21

Another incorrect assumption appears in reference to, "Riparian wildlife, some types of recreation and aesthetics may prove to be equally important, but because less is known of their specific relationships to power production it is more difficult to speculate on the relative probabilities that a given alternative might lead to a greater or lesser accommodation by utilites or the region generally." This statement is presented in a method which misconstrues the relationship of power production and wildlife. To state that it is difficult to speculate on effects of an alternative might lead to a greater or less accommodation of riparian wildlife. This tends to ignore presently accepted facts. 22

Our primary goals concerning energy production in the Pacific Northwest are: protection and enhancement of Columbia and Snake River anadromous fish runs; preservation of riparian vegetation along Sanke and Columbia Rivers to provide wildlife habitat for both game and non-game species; and continued assurance that other non-power hydro-uses such as hunting, fishing and recreation will be given 23

Page 6
June 11, 1980

equal consideration with power uses. To assure these goals BPA must propose not only alternatives that encourage conservation but include programs that actively mitigate and compensate for impacts on fish and wildlife as a result of construction, generation, and transmission of power in the Pacific Northwest.

Thank you for the opportunity to review your document. We hope you find our comments helpful.

Sincerely,

THE DEPARTMENT OF GAME

Mark Grandstaff

Mark Grandstaff, Applied Ecologist
Environmental Affairs
Habitat Management Division

MG:mjf

cc: Agencies
Regions

Letter #36

FERN

Fair electric rates now.

June 11, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621 SJ
Portland, OR 97208

Re: Revised Role Environmental Impact Statement

Our comments on the revised EIS will be confined to two areas, rates and thermal resources. Our primary interest is in the area of rates. Our comments on thermal resources are largely technical points.

RATES

BPA is presently not fulfilling its proper role under existing legislation
in the area of rates. Existing legislation provides that the system is
to be operated primarily for the benefit of domestic and rural power users
with particular attention given to public bodies and cooperatives. Presently,
Bonneville's rates are established in a manner which does not provide for
this statutory preference. Additionally, Bonneville's own rates, and most 1
of those in place at the local utilities served by Bonneville, are discriminatory
under the standards developed by the United States Department of Energy. An
important role of BPA should be to establish rates consistent with the present
legislation, and to insure that the retail rates of the utilities who buy
energy from Bonneville are nondiscriminatory. Both of these changes will
entail major alterations in BPA's present policies.

Bonneville is presently marketing power from various sources, with various
costs, ranging from inexpensive energy from the larger hydroelectric installations
to thermal energy from Trojan, Hanford, and perhaps eventually from WPPSS. To
provide the preference provided in law for domestic and rural customers, the
lowest cost resources should be reserved for these customers. Present price
melding conflicts with this. Statutory preference customers are receiving 2
part of their power costs from more expensive sources, which should be billed
to other than domestic and rural loads. Specifically, the higher cost resource
should be billed to the industrial loads served by Bonneville's wholesale customers,
and to the direct service industrial customers. Recent alterations to Bonneville's
rates have made this correction already for investor-owned utilities.

Bonneville is not filling its role properly, nor observing the current
statutes with rates which provide power at lower cost to direct service
customers, under rate schedule IF-2, than is available to investor-owned 3
utilities in the Northwest under schedule H-6. Proper implementation of
Bonneville's current statutory role would recognize that Northwest investor-

7241 Commercial N.E., Olympia, WA 98506

owned utilities have priority over direct service customers, and should not be paying a higher rate, but rather receive a preference over such industrial customers.

Essentially, under current law, Bonneville should be providing energy at
rates consistent with the provisions which provide priority for certain types of 4
loads. This can be done in a manner consistent with sound business principles,
by moving away from average cost pricing. Such an alternative is discussed
in "Alternative 4" of the revised EIS, and should be implemented.

Present rates, selling energy at melded costs, fails to meet any of the
current tests which BPA's rates should face up to. Preference to domestic
an rural customers is not provided. Industrial customers get power at lower 5
cost than preference utilities. Rates are inconsistent with sound business
principles, specifically, by selling energy from thermal resources at rates
far below cost, while selling energy from existing hydro installations at
rates well in excess of cost. Alternative 4 provides a resolution of this
inconsistency in a manner which meets the requirements of current law.

Elimination of discriminatory rates should be a priority role for BPA.
DOE policy on ratemaking has been established, through publication in the 6
Federal Register on February 22, 1980. In the voluntary guideline for solar
and renewable resources, promulgated by the Secretary under PURPA, DOE
takes the position that rates not based upon marginal cost are discriminatory.
While BPA should be implementing rates which encourage the use of solar and
renewable resources for other reasons, the discrimination issue is one in
which BPA should be playing a major role.

Presently, BPA, unlike other utilities in the region, is basing rates
upon average, or embedded costs. Utilities such as Pacific Power and Light,
Portland General Electric, Seattle City Light, and Puget Sound Power and
Light have encouraged their regulatory officials to base rates upon marginal 7
cost. Moves to marginal cost do not entail rates which generate more revenue
than is required or permitted. Each of these utilities have rates which
generate only the allowable revenue. BPA, on the other hand, has rates which
discriminatorily favor large users over small, by loading too much of the
revenue into demand charges, and too little into energy charges. As a
result, industrial customers pay less than their share of required revenues,
while others subsidize the shortfall.

Given the fact that BPA policy is to encourage rates based upon marginal
cost, BPA's role should be to implement this policy in their own rates,
and require that any utility buying power from them do the same. To do 8
otherwise is discriminatory, prohibited under the Bonneville Project Act, and
contrary to national energy policy, as voiced by the Secretary.

None of the alternatives discussed in the revised EIS deal with this alteration in rate form. The previous rate hike EIS of August, 1979, did discuss moving to marginal cost pricing, but only in a manner which would have generated excess revenue. BPA needs to re-analyze an alternative which combines the preference policies discussed in Alternative 4 of the revised EIS, together with rate revisions for their own and their customer's rates which are consistent with DOE policy. The environmental impacts of enhanced energy conservation should be thoroughly considered, and such a change in BPA's role, from one they have ignored in spite of legislation requiring such changes, should be implemented immediately.

THERMAL RESOURCES

The discussion of thermal resources needs to be updated considerably.
The tables on page IV-26, for example, ignores a number of thermal plants,
includes some no longer considered active, and have out-of-date operating 9
dates for most units. Additionally, the estimated cost of power from the various
thermal plants which appears in table IV-5 bear little relationship to the
actual or reasonably anticipable costs of power from these units.

The discussion of thermal plants does not refer to Jim Bridger #4 as an
operating plant, which it has been since December, 1979. Several plants
which will be available to serve regional loads have been entirely omitted.
These plants are Wyodak #2, a 330 MW coal-fired plant announced by Pacific 10
Power, Valmy units 1 and 2, jointly owned by Sierra Pacific Power and Idaho
Power. Together with the interconnections which will be provided with this
plant, additional capacity, and some energy, will be provided to the
Northwest. Under several alternatives discussed, increased BPA participation
in serving loads through Idaho Power have been considered. Valmy should
be added as a generating resource. Wood-fired plants are under development
by Lewis County PUD and by Washington Water Power. The Creston coal-fired
facility under development by Washington Water Power has also been ignored.

The Skagit and Pebble Springs nuclear plants are still listed as thermal resources. Even the official dates for these projects have been slipped out of this decade. They should not be a part of the list of thermal resources.

The cost of power for most of the thermal plants bears little relationship to 11
what has actually been paid for the actual output of these plants. Table
IV-5 should be revised to be more consistent with reality.

The cost from the Hanford Generating project should be amended to include the
costs incurred by the Department of Defense for operation of this facility.
Since there is not currently a need for the byproduct of steam generation,
this cost should be fully allocated to energy. For the Centralia plant,
it appears that the cost has been figured on the basis of a 75% plant factor;
this has never been realized at Centralia, and should be recalculated at 60%.
Additionally, it appears that the costs shown assume tax-exempt financing, 12
as portions of Centralia are owned by municipal agencies. A note detailing that
costs should be higher for the privately financed portions should be provided.

Both of these criticisms of the Centralia figures also apply to Trojan. BPA paid 60 mills for the power it received from Trojan in 1978. Never has a year gone by where the plant provided energy, even to the EWEB financed portion, at a cost of 14 mills. An average of actual expenditures should be substituted for those shown in the table, taking into account the low plant factor of this unit. Again, a note regarding the higher cost of privately financed portions of the plant should be provided.

The units under construction suffer from similar problems. Jim Bridger #4
is now operating, and PP&L should be able to provide busbar cost for that
unit, which was completed at a cost 32% below budget. The WPPSS plants 13
will provide power at much higher cost than those shown. While the table
shows busbar cost for WNP 4 at 33 mills, the WPPSS bond statement of April
14, 1980, shows a cost of 65-72 mills for this project. With additional
cost increases being included in the 1981 budget, now under development,
this cost will increase further. The other WPPSS figures shown are similarly
unrelated to reality. Even the WPPSS bond statement assumes a 70% plant
factor, unlike to be achieved by a large nuclear-fueled plant, based upon
industry experience.

Cost for the Boardman plant should now be available from PGE. This plant 14
is scheduled for commercial operation this summer, and it should be possible
to make an estimate (at least as useful as any of the others) for a plant
so close to completion.

We agree that estimating costs for the Skagit and Pebble plants is illogical. In testimony before the Atomic Safety and Licensing Board on the Skagit project, a busbar cost of 60.5 mills was used, but that assumed that construction could be carried out at less than $1500/kw. With WPPSS #5 now budgeted for over $3000/kw, the old Skagit estimates are meaningless.

Table IV-6 appears to exclude the net-billed thermal projects. The owners 15
of these projects refues to acknowledge that the debt is their own, arguing that
it is really BPA's debt. Either the EIS should include that as a BPA obligation,
or a letter notifying the participants that the debt belongs to them should
be drafted.

We appreciate the opportunity to comment on the revised EIS. If we can be of further assistance, please feel free to contact us.

Sincerely,

Jim Lazar
Research Director

Letter #37

LANE COUNTY AUDUBON SOCIETY

AN OREGON CHAPTER OF NATIONAL AUDUBON SOCIETY

P.O. BOX 5086 • EUGENE, OREGON 97405

June 11, 1980

Environmental Manager
Bonneville Power Administration
P. O. Box 3621-SJ
Portland, Oregon 97208

Dear Sir:

We would like to enter the following comments into the public record on DOE/EIS-0066 dated April 1980:

1. We feel that a system similar to alternative 1 would be the most acceptable. BPA's role is to transmit and market power. The final decision as to the type and nature of a power generation facility should lie within the control of the people most directly affected. Many people would be willing to pay an increased utility rate for an alternate source of power rather than breathe the ash residue from a coal fired plant.

2. We do not agree that nuclear power is the most environmentally sound alternative. Some of their side effects include elevated water temperatures, increased fog from cooling tower plumes, ice fog in colder climates, and the obviuos danger from radioactivity. It is no longer so easy to say that a nuclear accident cannot happen.

3. We do not feel that "worst case" scenarios are a totally appropriate decision making tool. If the worst case is all that is available, then all the alternatives have not been considered.

4. One avenue of conservation possibilities has not been
explored, that is the rate structure. It is time that we
quit rewarding industries for being electrically inefficient.
The wholesale electrical supply currently given to the
direct service industries not only encourages the use of
outdated electrically inefficient processes, but also is 1
totally unfair to those idustries who don't have this
kind of power available to them. A stepped or inverted rate
schedule would make conservation a viable alternative and
encourage cost effective methods of process and co-generation.

DOE/EIS-0066
page 2

5. We support the use of mandatory building energy standards as a method of energy conservation.

6. We disapprove of the use of aerial spraying as a means of transmission line vegetation management. There is no way to control the potential damage from the use of this type of management.

7. Sparse data is given on the coats for compressed air storage,
the Electrical Power Research Institute Journal (Vol. 5
No. 3) indicates that the capitol costs of this system would 2
be less than $300/KW and the annual coats would be 35/KWH,
citing this system as the most economical. The same publication indic'tes that storage batteries have a capitol
cost ranging from $80 to $700 per KW rather than the figures
shown in table IV-25.

8. When considering threatened and endangered species, the species 3
and habitat protected should include those listed by state
authorities as well as Federal.

9. The storage of spent nuclear fuel from reactors is indicated due to a lack of technology. It is not acceptable to allow the continued construction of nuclear plants when the technology for disposing of the wastes is not available.

10. Using the least expensive energy source (hydro-power) for
peak demand loading is not cost effective. The use of time
of day billing rates has reduced peak demand loading for 4
many private utilities and would have the same effect for
the BPA. The use of hydro-power for base line and an
alternate renewable storage mechanism (solar or batteries as
examples) for peak loading with a rate system that reflects
the associated costs would appear to be the most beneficial.

11. If the long term effects of hydro peaking operations on threatened and endangered species is not known then hydro peaking operations cannot be allowed until it's safety is established.

Sincerely;

Jeff Graper

Jeff Grapel
Conservation Committee
Lane County Audubon

Letter #38

United States Department of Agriculture

Soil Conservation Service

1220 S.W. Third Avenue
16th Floor
Portland, Oregon 97204

June 12, 1980

Mr. John E. Kiley, Environmental Manager
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

Dear Mr. Kiley:

The Soil Conservation Service has reviewed the revised Draft Environmental Impact Statement concerning BPA's role in the development of the Pacific Northwest regional electric power supply system through 1998.

We have no comments to offer.

We appreciate the opportunity to review and comment on this draft.

Sincerely,

G H Wilhelm Jr

GUY W. NUTT Acting
State Conservationist

cc: Administrator, SCS, Wash.,D.C.

The Soil Conservation Service is an agency of the Department of Agriculture

SCS-AS-1
10-79

Letter #39

OREGON VOICE OF ENERGY

PO BOX 8526
PORTLAND, OREGON 97207

June 11, 1980

Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

Attention: Mr. John E. Kiley, Environmental Manager

Subject: Comments on BPA's Role E.I.S.

Gentlemen:

We support alternative No. 3 because it would provide for the cost-effective development of new generation capacity which we feel is vital to the economic well being of the Pacific Northwest.

Sincerely,

OREGON VOICE OF ENERGY

T W Tucker

Tom Tucker
Chairman
Research Committee

Letter #40

NORTHERN PLAINS RESOURCE COUNCIL

Main Office
419 Stapleton Bldg
Billings Mt 59101
(406) 248-1154

NORTHERN PLAINS
RESOURCE COUNCIL
P. O. Box 858
Helena, Montana 59601
443-4965

Field Office
PO Box 886
Glendive, Mt 59330
(406) 365-2525

June 10, 1980

The following represent the comments of the Northern Plains Resource Council on the BPA Revised Draft Role EIS. The comments are not exhaustive in their detail but instead are directed to the general ideas contained in the Revised Draft.

1. The first place to examine for the comments and attitudes of the NPRC would be to re-examine the comments made on the original Draft Role EIS by NPRC in 1977. The comments made by NPRC and by the individual members of NPRC are still valid as of this writing. The responsiveness and sensitivity of the BPA to the concerns of Montanans has changed little. BPA essentially remains the same agency that it was in 1977. The Draft and the Revised Draft show little increase in awareness. The Revised Draft may have been issued to meet NEPA and CEQ guidelines, but it does not appear that the drafters took any of the criticisms of Montanans under advisement. Look again at the original record. 1

2. The major impetus for this soul-searching that is done in the Revised Draft (as was done in the original Draft) appears to be the imminent passage of some sort of Northwest Power Legislation. To the extent that the Revised Draft relies on the whim of Congress to pass or more significantly, not to pass, the latest verson of the "BPA Bill" the entire effort is flawed. At this writing the success or failure of this year's legislation is not assured. It is highly inappropriate for a federal agency such as BPA to be fostering and promoting the passage of such legislation.

3. If BPA is as truly concerned with its authority to promote conservation and renewables as the EIS purports it would do well to examine the implications of legislation that has already passed through the House which amends BPA's authorization to allow for expenditures for conservation and renewables.

4. As was stated in the original draft, Montanans, particularly Eastern Montanans, are not reassured that BPA will be responsive to their concerns under a "one utility" concept. The entire notion of one utility needs to be examined more closely for benefits and costs. The costs to Montana of a one utility reality are excessive and unfair because Montana would become the generating and transmission area.

5. Whatever role the BPA assumes will be outlined by statutory limits. Regardless of the role itself, if BPA's flagrant disregard of the Montana Major Facility Siting Act and arragont attitude towards landowners in the BPA Colstrip Transmission Line controversy is an indication of the future we all will be losers. BPA adamantly refuses to comply with State Siting Authority. This is not a model for federal/State cooperation.

June 10, 1980
NPRC comments

There is no indication in the EIS of any concrete examples of where BPA has followed State Siting Authority. The role of the BPA should most definitely not be to avoid compliance with State law and to avoid the payment of local and State property taxes. Until there is a marked change in direction any role that BPA takes would be inappropriate. 2

Submitted by Steve Doherty Steve Doherty
Helena Field Office - NPRC

Letter #41

'Retyped from Original'

Eugene Stuckle
Rt. 2 - Box 45
Davenport, WA 99122

Environmental Manager
Bonneville Power Adm.
P.O. Box 3621 - SJ
Portland, Oregon 97208

Dear Sir:

I wish to make some comments regarding the Bonnaville Power revised draft Environmental Impact Statement:

I would encourage Alternative 3 as outlined, giving BPA an increased role in the region. If present legislation should fail in Congress, new legislation should be introduced. This legislation would give BPA authority to purchase electric energy from non-Federal generating plants, sufficient to meet the region's firm loads.

People of the Northwest need assurance of continuing electrical supplies.

The preference clause must be maintained. No new utilities should become preference customers of BPA that are not bonafide utilities.

Conservation must be considered as an energy resource and must be encouraged.

If one-utility develops and operates the regional power supply system, the environment and economy will benefit.

Yours truly,

Eugene Stuckle

Letter #42

office of program research

WASHINGTON STATE HOUSE OF REPRESENTATIVES
ROOM 202 HOUSE OFFICE BUILDING, OLYMPIA, WA 98504 (206) 753-0520

June 12, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon 97208

Dear Sir:

I had hoped to complete a review of the Role EIS and June 12 arrived without my having been able to do so. I did get part way into it and my reactions are offered, recognizing that I may not have gotten to portions which would speak to my concerns.

First and foremost, it is well and very interestingly written (I'd be very surprised if there weren't considerable editing by Mike Katz) and the proposal and preferred alternative are the best choices. Moreover, the other selected alternatives are wise selections from a wide range of possible choices.

Another beauty of the book is that it is a wonderful reference compendium of history and current facts. Also, I like the 3 "tiers": Summary, overview, and the full text.

Criticisms:

Do we still have some excess baggage in the environmental analyses? I'd be inclined to be austere in stating absolute impacts so as to let the environmental impact differences between the alternative BPA roles stand out. While the differences are brought out in the full text, treatment of differences wasn't discernible to me in either the summary or the overview. As an example, on page I-36, the point to make is that the proposal or preferred alternative would do the listed things better than the alternatives. 1

The fact that energy resource scenarios were chosen to be extreme, the logic for doing so, and the expectation that reality would be in between is discussed nicely on pages IV 191-192. I'd get some of the logic of the top paragraph, page IV 192 into the middle paragraph, summary page v. (e.g. "the real future 2

Letter #42 (continued)

PAGE 2

won't reach any of these extremes, but the extremes were chosen to bond the impacts"). Inference from "worst case" seems a bit of a stretch.

A typo on page IV 196: Solar central peak should be 13,000 instead of 1,300. 3

Sincerely,

Frederick S. Adair

Frederick S. Adair
Senior Research Analyst
House Energy and Utilities Committee

FSA:jm

Letter #43

ENVIRONMENTAL IMPACT ASSESSMENT FORM
Request for Environmental Impact Evaluation

TO: Five Valleys District Council
Areawide Clearinghouse
Missoula County Courthouse
200 W. Broadway
Missoula, MT 59801

FROM: Montana State Clearinghouse
Office of Budget and Program Planning
Capitol Annex
Helena, Montana 59601

Environmental Impact Assessment Title: Revised Dravt EIS "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System Including Its Participation In A Hydro-Thermal Power Program

Clearinghouse File Number: E-80-04-02

EIS Agency Sponsor: U. S. Dept. of Energy

SPONSOR ADDRESS: Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

CONTACT PERSON: Environmental Manager

COMMENTS DUE BY: June 12, 1980

The Above Named Statement

_____ is enclosed for your review and comment
_____ should have been received by your agency from the sponsor
_____X is available at the Clearinghouse Office for review (only one copy was received).

Please evaluate the assessment for its consistency and fullfillment of statewide and local objectives related to:

1. The Environmental impact of the proposed action.
2. Any adverse environmental effects which cannot be avoided should the proposal be implemented.
3. Alternatives to the proposed action.
4. The relationship between local short-term uses of man's environment and maintenance and enhancement of long-term productivity.
5. Any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

IF YOUR AGENCY HAS COMMENTS ON THE ENVIRONMENTAL IMPACT ANALYSIS, PLEASE SEND THE COMMENTS DIRECTLY TO THE AGENCY SPONSOR AND FORWARD A COPY OF THE COMMENTS TO THE STATE CLEARINGHOUSE.

IF YOUR AGENCY DOES NOT INTEND TO COMMENT, PLEASE CHECK THE BOX BELOW AND RETURN THIS FORM TO THE STATE CLEARINGHOUSE.

X **NO COMMENT**

Reviewer's Signature Ethel MacDonald

Title A-95 Coordinator **Date** 6/13/80

Letter #44

HANFORD ENERGY CENTER PROGRAM
DEVELOPING A REGIONAL ENERGY SYSTEM

June 12, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, OR 97208

Dear Sir:

We have received BPA's Role EIS (DOE/EIS-0066) and offer the following comments for your consideration.

We are in full agreement with BPA's proposal to encourage conservation, renewable resources and the coordinated operation of regional generation and transmission facilities. However, care should be exercised that we do not place too much emphasis and optimism on untested and unverified resources that we forget to provide realistic contingency plans based on proved resources.

The approach used by the EIS to evaluate the environmental impacts of future power systems by examining scenarios representing extreme cases is appropriate. This approach should envelope the potential impacts from any combination of resources which may in fact evolve. However, the revised EIS does not carefully distinguish between what is "theoretically possible" and what is "realistically achievable" as claimed on page I-23. On page IV-194 (top paragraph) it is stated that a combination of conservation and renewable resource could be capable of meeting regional needs. Such a conclusion does not appear to be supportable. 1

In particular, no words of caution, no clarification of theoretical or realistic, etc., are included in the Summary. Since the Summary will probably be used by the media and many decision-makers for information, it is essential that it be prepared with caution and perspective. 2

POST OFFICE BOX 1390, RICHLAND, WA 99352 • 509/946-9629

Environmental Manager
June 12, 1980
Page 2

We appreciate the opportunity to submit comments on this document.

Sincerely,

R.A. Newkirk

R.A. Newkirk

ua

Enclosure: (1)

Letter #44 (continued)

Comments on Revised Draft

BPA Role EIS

No.	Section/Table	Comment	
1.	IV-Intro (pg IV-1)	In the first paragraph the statement is made: "It is very unlikely that any of the five scenarios described in this chapter would actually develop, including the worst-case of all future load being met by nuclear plants." While we do not advocate a "100% nuclear" scenario, such a scenario certainly would not represent the worst-case environmental impact. This statement is not substantiated by the information presented in Section IV, nor is it substantiated by the operating experience of power reactors in the Northwest to date.	3
2.	IV.B.1.b.(2) (pg IV-100)	The second paragraph of this subsection includes the sentence: "Environmental impacts of generation insufficiency would be greater than those of a sufficient power system." This is a highly significant conclusion and should be emphasized in the Summary.	4
3.	IV.B.3.c.(1) Table IV-32	The assumption that Solar Central Stations can be constructed at a rate which would result in an installed capacity of 13,000 MW by 1998 does not appear to be credible given the current status of DOE programs in this area.	5
4.	IV.B.3.c.(1) Table IV-32	The assumption that 5,000 MW (installed capacity) can be realized from Large Wind Generators does not appear to be supported by section IV.B.2.b.(5).	6
5.	IV.B.3.c. (pg IV-194)	In reference to Scenarios A and B (100% Renewable Resources and Maximum Conservation) the statement is made: "Most individual resource types considered here are not sufficient by themselves to meet projected loads under current estimates of potential, but collectively they appear to be capable of meeting regional needs."	7

No.	Section/Table	Comment	
		In our opinion, this statement misleads the reader as to the potential of these resources and fails to distinguish between the theoretical and the realistic. We strongly believe that this type statement cannot be supported.	
6.	IV.B.3.c.(1) (pg 198)	The summary discussion impacts which are not quantifiable should be updated with respect to large wind generators. The only impact mentioned refers to interference with television and radio signals. It is our understanding that the Department of Energy's 2 MW windmill at Boone, North Carolina was recently forced to shutdown due to effects of a very low frequency sound which was generated during operation. This impact would appear to be more significant than localized TV interference.	8
7.	Tables IV-39 41, 42, 47, 48	All of these tables appear to include gross errors with regard to air emissions from nuclear plants. Similar errors may exist with regard to the solid waste quantities listed. The following comparison is offered between the data presented in Table IV-39 for the Pebble Springs and Skagit plants and the data in the Final Environmental Statements for these plants:	9

Air Emission (tons/yr)	Table IV-39	Skagit FES	Pebble FES
Sulfurous	25,000	<1	<1
Nitrous	6,620	6	5
Particulate	6,120	<1	-
Hydrocarbons	76	<1	<1
Carbon Monoxide	None	1	1

Since the same source document was used for estimating the emissions from future, yet to be announced nuclar plants, all the tables with nuclear plant air emissions would appear to be in error.

No.	Section/Table	Comment	
		We are not familiar with the basis for the solid waste estimates, however, it seems unlikely that the solid waste estimate for the all-nuclear scenario would exceed the all-coal scenario by a factor of about six as indicated by Table IV-42.	10

Letter #45

State of Montana
Office of The Governor
Helena 59601

THOMAS L. JUDGE
GOVERNOR

June 12, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon 97208

Dear Sir or Madame:

This letter is the response of the State of Montana to the revised draft role EIS for the Bonneville Power Administration.

The revised draft, with its shorter length and more compact format, is a much more readable document than the first draft. However, a review of this revised draft reveals very little response to Montana's extensive comments on the first draft. I therefore question the sincerity of BPA in asking for comments on this draft and enclose another copy of Montana's original comments.

Over the last several years, I have observed BPA and its changing role in the Pacific Northwest power supply system. BPA has evolved from a relatively benevolent marketer of low-cost federal hydropower and builder of essential federal transmission facilities to an aggressive regional utility. Indeed, BPA personnel sometimes use the word "utility" in describing the agency, despite the absence of statutory authorization to perform the utility function.

Perhaps the most troublesome aspect of the expansion of BPA's role has been the recent intrusion into planning and construction of heretofore private utility transmission lines, which at least gives the appearance of an attempt to circumvent the Montana Major Facility Siting Act. The most publicized example is the Townsend-Hot Springs 500 kv line, originally proposed by a consortium of Pacific Northwest utilities led by the Montana Power Company; others may include the Fall River line to West Yellowstone, the Washington Water Power line from Noxon to Pine Creek, and the Pacific Power and Light line west from Libby.

We in Montana do not object to BPA playing a coordinating and integrating role in the regional power system. We do, however, object to attempts to subvert the Montana Major Facility Siting Act. We object to the loss of tax revenues to local governments when BPA takes over private projects, especially when the beneficiaries of those projects are residents of other states. And we object to the manner in which BPA fails to meaningfully involve the state in its decision-making process, despite the state's authority and responsibility in the area of power system planning and regulation.

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Herein lies a major weakness of the proposed alternative in the draft role EIS. Failing to meaningfully involve the states can only lead to confrontation, litigation and delay, all to the detriment of the electrical consumers and ratepayers of the region. 1

I also question the efficacy of this role EIS process. BPA continues to refuse to meaningfully examine or consider alternatives to the "...concepts fundamental to power system planning...," including generation and transmission system reliability standards and critical period planning. Decisions regarding acceptable levels of reliability and critical water planning criteria are primarily questions of policy and not engineering. 2 BPA simply assumes that these policy questions will be answered only by utilities. No mechanisms for public scrutiny or public input are considered. So long as the fundamental assumptions underlying any BPA role are not addressed, the role EIS will remain largely a pro forma exercise.

Sincerely,

Thomas L. Judge

THOMAS L. JUDGE
Governor

cc: Ted J. Doney, Director
Department of Natural
Resources and Conservation

COMMENT 1 FORMAT, ORGANIZATION AND GENERAL APPROACH OF THE DRAFT ROLE ENVIRONMENTAL IMPACT STATEMENT

The instructions for commentators include a request for comments on the format of the Statement, and suggestions on how changes in "packaging" might improve its use. The instructions also state that "although all the information contained in the document will prove useful, the format of the EIS might be improved."

A "repackaging" of the statement will not be sufficient. It is doubtful that "all the information...will prove useful" to the reviewer who seeks to adequately evaluate the action (BPA's future role) which is being proposed--much of the information only tends to confuse the reader who seeks to find the real substance of the document and the proposed action. 3

We recognize that writing an environmental impact statement on an entire agency program is unprecedented, and that BPA faced a very difficult and complex task in deciding what the role EIS should include. Prior to crafting the final EIS, we suggest that those responsible for the statement carefully review the basic purpose for the project. As we understand it, that purpose is to examine carefully BPA's present and potential future roles in view of their present and future potential environmental impacts. Many of the criticisms which follow are a result of what we perceive as an essential failing: In trying to cope with a vast amount of information, the drafters of the EIS seem to have lost sight of the task of evaluating the impacts of BPA's activities.

Is all the material in the EIS necessary to assess the environmental impacts of BPA's program? No.

The Council on Environmental Quality's Guidelines for Preparation of Impact Statement states:

> In developing the above points (EIS contents) agencies should 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, giving attention to the substance of the information conveyed rather than to the particular form, or length, or detail of the statement. (emphasis added) 40 C.F.R. 1500.3(b) 4

The following entry in the minutes of a meeting of the Public Power Council on the subject of the Draft Role EIS, indicates the extent to which it fails to meet these requirements:

> Because of the complexity and short time frame involved it was determined by the committee that a full time expert in handling Environmental Impact Statements must be hired as soon as possible. (Oct. 3, 1977)

To understate the case considerably, the Statement is not succinct and does not give attention to the substance of the information conveyed.

Could the EIS be shortened without sacrificing its quality or usefulness as a decision making tool? Yes.

The question erroneously assumes that the quality of the Statement is adequate and is useful as a decision making tool as it stands; the draft is neither. As suggested in the comments above, the Draft Role EIS goes into extremely lengthly detail in some areas and almost completely ignores other important ones. For instance, how can a decision maker make intelligent choices regarding power demand and supply without a full analysis of the legal and environmental framework of coal supplying areas? The EIS gives the decision maker only part of the equation, contrary to the intent of an EIS, which is to give him or her all relevant environmental information.

The EIS could be shortened and thereby considerably improved by integrating, summarizing and better reorganizing the purely descriptive material. (Does a decision maker need to know the technical engineering details of how a coal-fired plant works in order to make intelligent decisions about energy in the Northwest?) Much of the draft role EIS resembles a badly written recipe: Many, but not all ingredients are listed; however, they are scattered throughout the cookbook, and the directions for how they might be combined are vague and incomplete; in addition, one does not know what the possible results might look or taste like.

Would the material be more useful for public review and to decision making if it were presented in a different manner: e.g., by including economic analysis in an appendix, or by separating the decision making material from the program description and impact analysis? Yes.

Could the material be presented to delineate the decision making points and alternatives more clearly? Yes.

Separating and highlighting decision making material is a necessary first step in making the material more useful. In addition, the decision making and environmental analysis sections must be supplemented and clarified. Simply rearranging the existing material will not adequately solve the problems which make this statement of very doubtful value to the public and other decision makers.

Description of the "Proposed Action"

An excerpt from the minutes of a meeting of the Public Power Council highlight an important inadequacy of the Draft Role EIS:

> There was considerable discussion about the definition of BPA's proposed action statement. Most people felt that it was not clear from the document what BPA was proposing. (Nov. 17, 1977)

If professionals in the electric power field cannot located the proposed action, it cannot be expected that public decision makers and the lay public will be able to do so. Efforts must be made to clearly convey what BPA wants to do in the Final EIS.

Description and Analytical Approach

In general, the descriptive portions of the EIS are much more extensive than necessary. The CEQ Guidelines suggest:

> A description of the proposed action, a statement of its purposes, and a description of the environment affected, including information, summary technical data, and maps and diagrams where relevant, adequate to permit an assessment of potential environmental impact by commenting agencies and the public. (emphasis added) 40 C.F.R. 1500.8(a)(1) 5

The descriptive material, which takes up most of the Statement, fails to fulfill its role and in fact has an opposite effect from that contemplated by the Guidelines: Its bulk and complexity confuse the essential issues and make an assessment of the environmental impact of the proposed action very difficult.

Throughout the Statement, the analytical sections are unsatisfactory. This is a serious defect, since analyzing the potential environmental impact of a proposed action is the very heart of an EIS. Very often, this failing is due 6 to a tendency to analyze impacts of individual processes (thermal plants, coal mining, transmission lines) without relating those impacts to the BPA's proposed action.

An example of this is Part 2, Chapter IX, Mitigating Measures. Much of the chapter is devoted to the proposition that impacts of energy development (rather than BPA's role in energy development) will be mitigated through "increased coordination" by the BPA. Given that increased coordination is part of the "proposed action" being assessed, this chapter offers the illogical 7 conclusion that the activity (coordination) will mitigate the activity (coordination).

In addition to this failure, many of the environmental assessment portions receive only cursory and inadequate treatment. Thirteen pages are devoted to analysis of mitigating measures which can be taken for one hundred six pages of "Impacts of BPA's Proposal." Mitigation should be a major part of the statement, and should include, among other items, an analysis of how to mitigate the adverse impacts of regional coordination, lessened public participa- 8 tion, lessened public accountability, the potential for large nuclear and coal-fired plants to the exclusion of alternative energy development, (See Part 2, Chapter XII, Page 2, Lines 9-27), weakened state environmental regulatory authority, intense local environmental impacts which are not fully assessed in regional programs. This list is illustrative rather than exhaustive; a concerted systematic effort must be made to identify potential adverse impacts which the mitigation section must then address.

The analysis of cumulative and indirect impacts is inadequate in its failure to realistically assess BPA's extremely important role in energy development in the region. For example, the EIS fails to evaluate transmission grid's influence on construction of facilities designed to tie into it (two 500 kV lines from Colstrip, Montana to Hot Springs, Montana).

The EIS fails to analyze the growth-inducing effects of BPA's proposed 9 action, which could include substantial population expansion in rural eastern Montana if minemouth plants are constructed. Cheap hydro peaking power and artificially low priced melded power could encourage population growth in the Pacific Northwest.

Another analytical defect is the failure of Volumes 1 and 2 to reflect the generally excellent analyses contained in the Appendices, particularly the discussions of reliability and forecasting. While the detailed studies raise a number of important policy issues and alternatives, these are not discussed in the first two Volumes, which seem to conclude that BPA's present reliability criteria and forecasting methods are the only realistic alternatives. 10

Scope of the Draft Role EIS

Although the EIS states that the scope of its evaluation was determined by where the most probable impacts were likely to occur, it would seem to be more than coincidence that it is limited to BPA's traditional statutory service area. Such artificial boundaries do not carry weight in legal literature concerning the National Environmental Policy Act. BPA must expand its environmental concerns and analyses to fit the expanded role it seeks to play in the Pacific Northwest. 11

COMMENT 2 BPA'S LEGISLATIVE MANDATE AND ITS INTERPRETATION WITH REGARD TO SERVICE AND PRICING

These comments pertain to Appendix C, Chapter II. BPA Marketing Program and Practices; Part A Section 1. The Nature of BPA's Policies; Part B Section 1, Marketing Policies Relating to Various Customer Classes, Section 3, Determination of Wholesale Rate Design and Rate Levels.

According to page II-3, l. 20-21 of the EIS:

"A primary objective is to encourage widespread use of electric energy." In the past BPA has interpreted the "widespread use" requirement as partial justification for acquisition of power to serve the increased demand of all its customers and to provide power to new industrial customers which met some conditions of size and quality of power. (See PII-31, 4-16) This interpretation seems to conflict with the current national policy of energy conservation and BPA's own conservation policy outlined in Chapter IV, Section H of Appendix C. The EIS should address the apparent conflict between past and present policies and should outline the current interpretation of "widespread use" which allows conservation to be an important goal. 12

The role EIS states, "Since the (1971 industrial) policy has not yet been superceded, it is discussed in some detail here. However, it is expected that many features of this policy will change." (P. II-30, l. 54 & II-31, l. 1 & 2) In view of the nonrenewal notices the direct service industries (DSI's) and the conservation policy described in the EIS, the 1971 Industrial Policy should be changed. The change should be discussed and explained in the final EIS.

BPA's treatment of its Federal agency customers with demand limit contracts is inconsistent with a sound conservation policy. The role EIS states: "it is essential that minimum payment provisions be included in demand limit contracts" (P. II-27, l. 23 & 24). This minimum take-or-pay provision encourages the use of electricity for a system predicting regional shortages in the early 80's. BPA should review its present contracts and remove all clauses which would penalize its customers for not using energy. 13

Rate structure reform must be addressed by BPA.

> The FPC, in giving final approval of BPA's present rate schedules on August 21, 1975, spoke on the need for change, saying BPA is '...urged to examine on an expedited basis time-of-day pricing as an adjunct to the rate design changes already adopted. Careful consideration of rate designs directed toward bringing rates more closely into alignment with costs by agencies such as BPA with its considerable expertise and resources would clearly be in the public interest.' (FPC, Opinion No. 741). (P. II-45, l. 24-31)

BPA's most noteworthy change in rate structure reform in 1974 seems to be the adoption of the seasonal rate concept on a moderate basis. BPA recognized a cost basis for seasonal rates, and adopted the seasonal rate concept in rate schedules for all but direct service industrial customers.

Although the EIS states:

> BPA's direct service industrial customers are not responsive to summer-winter rate differentials because of their high load factor characteristics; therefore, a differential for them serves no purpose (P. II-45, l. 43-46),

no evidence supporting this statement is given. With BPA in a transition between a hydro system and a hydro-thermal system, the summer-winter cost differential will continue to grow in the future. Whether or not these industries would be responsive to a rate differential, their use of energy contributes to the winter peak. If rate differentials are appropriate for some customers because of different summer-winter costs, then anyone contributing to winter peak and higher resulting system costs should pay a seasonal rate differential.

BPA seems reluctant to change its method of pricing its product from average cost pricing because its utility and DSI customers like the present system. (See discussion P. IV-232). This is not an adequate reason for continuing "business as usual" if another pricing method is more appropriate to accomplish a stated goal. If BPA's goal is conservation, then rates to encourage conservation must be designed. 14

> Over the years, BPA had designed rates to promote sprinkler irrigation, hot water heating, yard lighting, and other uses. BPA has encouraged high power load factors. It is entirely possible rates might be developed to encourage conservation. (P.II-15 l. 40-44)

It is submitted that the quickest, cheapest, and most efficient method to delay the impending energy shortages of the next decade is a solid conservation program, including BPA rate structures, which encourage conservation. The statement, "If BPA attempted to design rates to achieve a particular goal, cost based or not, the results of its efforts could be influenced by the rate setting policies of its utility customers" (P. II-43, l. 20-23), is an inadequate excuse. BPA wholesale rates will directly influence retail rates charged by utility customers because the utility customers must at least recover the wholesale costs. Modification of wholesale rates would not provide a complete solution, but would be a step in the right direction. 15

Because possible BPA future roles include significant BPA power purchases from non-federal thermal power plants, the EIS should address specific rate-making techniques which would determine the price BPA would pay. This is especially important for any detailed alternative future roles of BPA, such as that included in specific legislative proposals, e.g., the PNUCC legislation (S. 2080) and Congressman Weaver's legislation (H.R. 5862). In this regard, among the questions which the Role EIS fails to address are: 16

1) Will the sale of power between the non-federal supplier and BPA be subject to regulation by FERC?

2) What return on equity will be allowed on the non-federal suppliers investment?

3) Will construction work in progress (CWIP) be allowed in the rate base?

4) Will revenue requirements be computed on an average or year-end rate base?

5) Should CWIP not be included in rate base, what interest rate for allowance for funds used during construction (AFUDC) will be allowed by BPA?

6) Will a state's ability to properly regulate its utilities be circumvented if BPA becomes a purchaser of non-federal sources of power without regulatory guidelines regarding methods used in developing revenue requirements?

These questions must be answered in the final EIS.

Letter #45 (continued)

COMMENT 3 CONSERVATION

The following comments pertain to Part 1. Chapter IV

The accuracy of load forecasts depends upon many factors which influence the demand for electricity. However, the recent trend in annual growth rate, according to BPA has declined from 5.2 to 4.7%. Other forecasts (Northwest Energy Policy Project) range from 6 to 1.43% and Pacific Northwest 17
River Basin Commission ranges from 6.4 to 3.0%. The problem of forecasting loads from uncertain projections could result in an over-installed system for a period of time which could prove expensive in excess capacity, while a low estimate could cause a hardship on the users. (p.IV-111, 1.10)

Though energy conservation measures are important in light of shortages and escalating costs, a long term strategy (short term is temporary and offers no solution to the problem) must be developed for extending the supplies of available energy. (p.IV-112, 1.43)

In regard to reasonable costs, the question arises--reasonable to whom? In October, 1977, the residents of Nashville, Tennessee, paid $14.70 for 500 kwh/month while residents of New York City paid $51.88 for the same amount of electricity. In the Pacific Northwest, the question of reasonable cost is further illustrated in the October, 1977, cost of 500 kwh/month in Portland ($15.05) and Seattle ($9.30). Portland residents pay over half again as much for electrical energy as Seattle in the same federal power system (Source: DOE) (p.IV-112, 1.46)

"It is essential to recognize that conservation will not eliminate the need for the construction of new electric generating plants." This is an unnecessarily strong statement as later in the same paragraph it is conceded that with conservation fewer additional generation and transmission facilities will be needed. (p. IV-113, 1.12)

"Potential for conservation and probable savings through conservation measures should not be assumed to be the same." This statement suggests that actual savings will be at a level between that presently achieved and the maximum projected. The bottom line on computing conservation savings can only come from an actual meter reading computed from some structural base period. (p.IV-113, 1.42)

The paragraph alludes to the difficulty involved in obtaining reliable savings estimates for building types, electrical equipment ... However, this problem will not be solved in the near future because of high energy audit costs and lack of qualified manpower, particularly in the industrial sector. (p.IV-114, 1.4)

While it is true federal and state agencies are involved in many aspects of conservation, in reality it will take years and vast sums of money to change habits, patterns of use and changes in life style to achieve any amount of significant energy savings. The affects of such changes are long range rather than immediate solutions. (p.IV-118, 1.25)

Montana's energy office also has been involved in conservation efforts. (p.IV-119, 1.26)

The State of Montana has also developed plans on how to implement thermal efficiency and lighting standards for new buildings and purchasing standards for energy efficient appliances. (p.IV-119, 1.35)

One additional barrier equal to the awareness of the benefits problem is whether an electrical energy supply problem acutally exists. People living in the hydroelectric producing areas view full reservoirs and well-lighted auto sales lots and justifiably question the credibility of possible energy shortages. The benefits from energy conservation through educational programs must be geared toward saving money. (p.IV-122, 1.36)

Current conservation efforts are difficult to measure. During the low water year of 1976-77 the Pacific Northwest was asked to voluntarily save 10%. The system never did exceed 8% and it was questionable whether this figure was accurate due to the present methods of measuring electrical energy savings. Throughout much of the year a true savings picture was further complicated by increased irrigation and the additional demands of new dwellings. Information was also not available on a state to state basis. The political division responsible for monitoring conservation efforts must be able to ascertain their effectiveness. (p.IV-117, 1.9)

A coordinating body is necessary in a common system built for reliability and coordination. If this sytem exists over a large region (several states) it is important that a certain amount of consistency is apparent in the entire conservation effort. (p.IV-123, 1.29)

The industrial customers would alter only slightly their use of electricity. Furthermore, the cost of conversion is not justified in many long established marginal operations. Also some commercial and industrial businesses must rely on the cleanliness of electricity for the production of their goods. (p.IV-122, 1.45)

State programs in Montana consist of tax credits for nonfossil energy generation systems, and income adjustment for capital investment for energy conservation. (p.IV-121, 1.41)

Incentive programs, particularly mandatory programs would require some type of federal or state legislation. To facilitate an acceptable mandatory program the funding and manpower to audit such a program is necessary. (p.IV-122, 1.16)

Conservation measures whether consisting of energy efficiency in buildings or active energy-use habits require a shorter time lag for implementation compared to installation of new thermal generation. Because of the great potential for conservation measures to save energy, widespread emphasis (funds and qualified personnel) should be placed on educational program to inform the public. Incentive programs both voluntary and mandatory can enhance the conservation effort. However, these programs would usually require federal or state legislation. (p.IV-125, 1.49)

Regardless of the conservation measures involved, the Pacific Northwest will continue to experience environmental impacts due to construction and operation of electrical generating facilities. In areas where transmission lines cross narrow valleys and multiple power corridors already exist, the use of underground transmission systems must be investigated. The advantages of underground transmission lines also eliminate wind, ice and snow damage to the system. (p.IV-126, 1.47)

Electrical power plants are installed at various locations for several reasons: the desirability of generating power as close as possible to the load centers; limitations on the quantity of pollutants being released at one location, or the siting of electric plants at the locations where hydropower or fuel is available. In the Pacific Northwest most of the productive hydro sites are occupied. If power plants are sited near the load centers this would entail locating them west of the Cascade Mountains as 83% of the Northwest's electricity useage is found along the Pacific coast. If the siting of electric power plants are near the fuel source which is most likely not near the load centers, transmission systems and pollutants will have an environmental impact on these areas. A cost-benefit analysis of such an impact with legislative attention will determine the feasibility of such a system. (p.IV-113, 1.13)

The potential benefits to be gained from techniques for managing and shifting electrical loads are not clear. However, the feasibility of remote load control and peak-load pricing is becoming more realistic. Historically, utilities have enjoyed a long-term pattern of declining costs and have promoted consumption of electricity through advertising and a variety of techniques. Recently the emphasis has shifted to reduced consumption of electricity and therefore hopefully less of a demand for generating facilities. If load management decisions are to improve the efficiency with which energy resources are used, they must be based on sound measures of the marginal costs of supplying service under different conditions. The potential particularly for industrial co-generation of power in the load management system is also of interest. (p.IV-195, 1.7)

Since conservation of energy is largely open to individual choice, it is important to inform the individual through energy conservation education programs. The money is well spent if that individual properly motivated takes the information and carries those conservation ideas to his job, civic organizations and becomes an example in his neighborhood. (p.IV-199, 1.7)

COMMENT 4 THE POTENTIAL FOR ALTERNATE ENERGY IN THE NORTHWEST REGION

The following comments pertain to Part 1 of the Role EIS, Chapter IV Future of Electric Power Development in the Region-Power Demand; Section B Conservation and Other Factors Affecting Future Power Demand; Section B, Part 4 Supplemental Energy Systems; Section B, Part 6 Summary and Conclusions. 18

Regarding the Technical and Economic Feasibility of Solar in the NW Region

In the summary and conclusions section of Chapter IV, the Role EIS reads:

> Supplemental energy systems, utilizing wood, solar, wind or geothermal power are not expected to significantly reduce regional electrical loads by 1995. Any applications of these systems would contribute to regional load reduction, but economic and technical factors indicate that such applications will be limited in number. (p.IV-108, 1.38-42)

Yet, earlier in the same chapter the text states that "solar heating of buildings and water through use of solar energy appear to be technically and economically feasible for the Pacific Northwest." (p.IV-189, 1.11-13) Nowhere in the section of Chapter IV which deals with solar energy is there any evidence offered either for or against the economic feasibility. Simply quoting collector prices on pages IV-187 and IV-188 does not constitute evidence. Cost of collectors is only one factor in an economic analysis which would determine the economic feasibility of solar radiation systems in the Pacific Northwest. There is no discussion of life cycle costing. There is no discussion of the economics of new coal-fired and nuclear central generating plants vs. the economics of solar radiation systems. Such discussion is absolutely essential to an understanding of the real economic feasibility of solar systems. At the International Conference on Alternative Energy Sources in Miami, reported in the December 8, 1977, edition of the Energy Daily, Professor Dennis Meadows of Dartmouth College argued that most "cost-benefit analyses fail to take into account certain disadvantages of conventional energy systems--especially electricity--and certain advantages of alternative systems." For instance, nearly 70% of the cost of electricity delivered to the residential sector stems from transmission and distribution costs. Meadows also reflected that the largest nuclear plants are operating at 48.7% efficiency.

BPA anticipates a three fold increase in the generation of electricity in the West Group Area by 1995. BPA also anticipates that this increase will be met by construction of coal-fired and nuclear thermal generating plants . If the economic feasibility of solar energy is to be determined, some method of comparing solar energy with coal and nuclear thermal electric generation must be elucidated. At a minimum, the method should seek to determine the cost of each mode for meeting and use energy requirements in a typical single family residence. For the Pacific Northwest area, there will be regional differences for such a residence. The average annual number of Btu's of heat can then be determined for each region. The cost to deliver the average number of Btu's can then be computed. The cost per million Btu's delivered to the residence from nuclear and coal-fired thermal electric should be roughly the same throughout the region, while the costs of solar energy will have to be determined on a site specific and system/design specific basis. This type of analysis must be made before any conclusions regarding theeconomic feasibility of solar energy can be drawn.

Although the report entitled Prospects for Solar Energy: The Impact of the National Energy Plan prepared by the Los Alamos Scientific Laboratory for the Department of Energy suggests that domestic hot water heating is economically unfeasible on a 10 year life cycle cost basis in the Northwest, it does demonstrate the economic feasibility of solar domestic hot water systems for all the states of the region except Washington when figured on a 20 year life cycle cost basis with incentives (p. 29, Maps 15 & 16). In light of this report, it is evident that BPA should refrain from publishing assertions about the economic feasibility of solar energy in the Northwest region, until it explains its methodology and data sources for such assertions. Such an explanation and data are not present in the Role EIS.

In addition to a determination of specific cost comparisons between alternative modes for the provision of space heating, the external costs (e.g. environmental impact, social costs, etc.) associated with each mode must also be computed and integrated in any analysis of economic feasibility. Most important, research is needed to determine the impact of the construction of coal and nuclear thermal electric plants upon the capital resources of the Northwest region. It may be the case that a programmatic committment to meeting a forecasted three fold increase in electric consumption through construction of thermal plants may deplete the capital necessary for a transition to renewable energy when fuel becomes non-existent and/or the environmental and social costs of thermal generation become prohibitive.

The inadequate analysis which characterized the EIS's stance regarding the economic feasibility of solar energy also characterizes its stance regarding the technical feasibility of solar radiation systems in the Northwest region. One particularly glaring deficiency in the discussion of solar system design is the absence of any mention of passive solar system design. The Ecotope group in Seattle has retrofitted some residences in Seattle with passive modifications. These modifications have resulted in the sun alone providing 90% of the home's space heating requirement. The analysis of the technical features of solar energy systems is cursory and the data that are presented, particularly Table IV-22, would indicate that even an active solar space heating system is technically feasible for the Northwest region (e.g., the Matthew's residence at Coos Bay, Oregon, provides 60-80% of the home's heating requirement). However, such vital information as the percent of annual heating requirements supplied by such an active system is not present in the table or the text.

Because of an absence of sufficient data and rigorous analysis, the conclusion that the "presence of solar units will not replace or delay the need" (p. IV-187, l. 17-18) for central station generation has no valid grounds. Moreover, if this were true, then it cannot also be true, as asserted in the third sentence of the same paragraph, that "the net impact on the environment should be positive, since solar heating and cooling displaces other forms of conventional energy production most of which affect the environment negatively" (p. IV-187, l. 21-23). The proposition implies that solar can

replace or at least delay central station generation. Such contradictions in the text might indicate an apparent lack of care and thought in the preparation of the renewable energy section in this chapter, and the reader may well be justified to suspect a bias on the part of BPA against the development of renewable energy in the Northwest region. If there is a bias it can not be based upon any rigorous empirical analysis but upon an ideological position that is more comfortable contemplating conventional energy strategies. It is also possible to interpret the apparent contradiction to mean that BPA thinks that solar energy is not viable in the immediate future but will become a viable alternative in the long run. If this is an accurate assessment of BPA's position, then certainly one must recognize that if solar energy is to become viable much more research, development and demonstration is required before we draw any firm conclusions about the technical and economic feasibility of solar energy in the Pacific Northwest. Unfortunately, BPA's premature conclusions would seem to discourage such further study.

Regarding the Impact of Solar Energy on Current and Future Electric Demands in the Residential Sector

In 1974, BPA's domestic customers consumed 33.2 billion kwh which is 29% of the total kwh of consumption among all of BPA's customers. BPA has projected a three fold increase in electric energy consumption by 1995 among its domestic customers. According to the role EIS,

> Water heating represents about 6% of the area's electric load. Depending on patterns of use, solar water heating systems might save as much as 2 percent of the area load. However, because the high costs of conversion would preclude use of such systems in many existing buildings, a savings of less than one percent of the area load is a more realistic estimate. (p.IV-189,l.13-17)

From an analytic point of view these assertions are not supported with any evidence. How does BPA determine that solar water heating systems might save 2% of the load? On what grounds did BPA conclude that the actual savings would only amount to 1% of the load? The reader is entitled to know the data and method used to compute such percentages. Moreover, virtually every study sponsored by the private or government sector concludes that domestic hot water systems are the easiest and most economical retrofit system of all.

Although water heating represents only 6% of thearea's load, water heating accounts for 26% of residential consumption of electricity, while space heating accounts for 34%. Together water heating and space heating account for 60% of the electric consumption in the residential sector. Given the proper incentives and assuming the institutional obstacles to solar development have been overcome, solar water heating and space heating could be installed on all new residences and most existing residences could be retrofitted with solar water heating and space heating. Assuming that solar space heating can provide 50% of the residence's annual heating requirement and that water heating can provide 80%, then the potential energy savings could be very significant and in fact reduce the need for the anticipated

number of coal and nuclear thermal plants. Although the Role EIS claims that "solar space heating offers a lower potential for conventional energy savings because peak space heating loads occur when solar radiation is least available" (p.IV-180, l.22-24), this claim is not necessarily accurate. Much of the Northwest is faced with extensive cloud cover during the peak space heating season, yet solar devices can still provide space heating. Clouds do not always prevent solar collecting in either a passive or active system. Moreover, thermal storage systems can store at least a few days worth of heat. In 1974, Henry Matthew's house in Coos Bay, Oregon, handled 85% of the heating load and 88% in 1975. A recent Portland General Electric solar economics study indicated that an 80 square foot collector capable of delivering the equivalent of 2,400 kwh in heat energy yearly would pay for itself in electricity savings in as little as nine years. (The study assumed prices of $10, $15, and $20 per square foot of collector for the entire system installed. The system's owner was expected to be in the 30% tax bracket and paying 10% in state income taxes. Utility rates were assumed to increase 9% annually and maintenance was figured at 1½% each year. The study also made certain assumptions about incentives and collector design.) Before any authoritative statement can be issued regarding the potential of solar energy in the Northwest region alone, more research must be conducted.

COMMENT 5 SALE OVER THE NORTH SOUTH INTERTIE

The following pertain to Appendix C:

Chapter II BPA Power Marketing Program and Practices

Part A Section 1 The Nature of BPA's Policies

Part A Section 2 Encourage Widespread Use

Part A Section 3 The Preference and Priority Policy

Part B Section 1 Marketing Policies Relating to Various Classes of Customers

Part B Section 2 Determination of Revenue Requirements

BPA's role as an electrical marketing agency is in continuous flux and although there is flexibility in the system to respond to changing needs, public and congressional support can play a major role in the future. Changes in the elctrical energy supply system must remain in harmony with the basic Act. (p.II-1, 1.1)

It is important to continue one of the objectives included in the Bonneville Project Act "to encourage the widest possible use of all electric power." Conservation policies promoting efficient energy use and reduction of waste through energy management programs are an integral part of this Act. (p.II-4, 1.25)

Electricity generated from federally financed works in the Pacific Northwest should be available to the greatest number of people on an equitable basis within the region. Uniform rates throughout the region benefit all concerned, while at the same time reflecting those costs associated with generation, transmission and distribution of such energy. (p.II-7, 1.38)

It is an important conservation tool to use the Pacific Northwest-Pacific Southwest Intertie to increase the suoply of energy in the Pacific Northwest through the interchange arrangement. Surplus energy which would otherwise be spilled displaces higher cost oil and gas fired generation. (p.II-33, 1.18)

It is essential to uphold the Northwest preference law (Public Law 88-552) limiting the sale of hydro generated energy in the Southwest to thatwhich is surplus to the needs of the Pacific Northwest. (p.II-33, 1.26)

The Intertie is also important to handle energy for which there is a market in the Northwest at a rate not less than the prevailing rate in the Northwest for comparable energy and may not be exported to the Southwest. (p.II-33, 1.48)

Letter #45 (continued)

To continue the convenient flexibility and coordination of the system, costs should be such that something is paid for both generation and transmission. Additional flexibility is gained in the system by recovery of the cost of the transmission system by equitably allocating between the federal and nonfederal power utilizing the transmission system.

COMMENT 6 DIRECT SERVICE INDUSTRY SALES

This comment relates to Appendix C, Chapter IV. Impacts From Sales to Industrial Customers.

The aluminum industry uses a significant portion of the energy generated in the Federal Columbia River Power System, purchasing that power at rates 19 currently set at about 3 mills per kwh. The justification given for such low rates is that the industries have an extremely high load factor and that the power is interruptible, and therefore low grade. Much is made of the benefits to the system of having a market for interruptible power, which permits a lower overall level of reserves. However, as pointed out elsewhere in these comments, BPA and the utility industry treat interruptible loads as firm loads in projecting the need for new resources. Because they are included in the total forecasted loads, how the interruptibility of these loads reduces the need for generation is not evident. Further, the EIS does not explain why a customer with a high load factor deserves a rate reduction, since the Pacific Northwest has an energy-limited rather than peak-limited electricity system. In an energy-limited system each use of electrical energy contributes to the need for new generation resources, a fact not ameliorated by a high load factor. Additional justification is necessary to explain why firm load customers are not in fact subsidizing energy use by the interruptible, high load factor direct service industry customers.

The pricing of electricity in the Pacific Northwest shares an important characteristic with pricing in other locations, namely an insistence on using an averaged, historic cost of facilities to determine the selling price. In the energy-limited Pacific Northwest the true economic cost of electricity is the opportunity cost of the resources necessary to expand production of electric energy, i.e., the incremental cost of new generation. An approximate figure for this incremental generation cost is about 30 mills per kwh. The EIS reports the historic average electricity costs to the aluminum industry to be about 3 mills per kwh in the Pacific Northwest. Use of average pricing is therefore significantly undervaluing electricity for industrial customers. There are two major impacts associated with the understatement of electricity costs to industrial users. One is that the benefit of switching to energy efficient technology is understated; the second is that, particularly in the case of an electricity intensive commodity like aluminum, the cost of the product is understated significantly with consequent overuse, inefficient use, and inadequate recovery of waste products.

Rough calculations from the data presented in the Role EIS, in the subsection 7 of part E, Chapter IV, Appendix C, entitled "Impacts from Alternative Industrial Sales Policies" show that the estimated production cost of aluminum in old technology plants, which require 9 kwh of electricity to produce one pound of aluminum, is 37¢/lb., of which 2.7¢ is the cost of electricity priced at 3 mills/kwh. For plants using newer technology which requires 6 kwh to produce one pound of aluminum, the estimated cost of production is about 36¢/lb., of which 1.8¢ is the electricity cost. If electricity were priced at its true economic cost of about 30 mills, old technology plants would use 27¢ worth of electricity per pound versus 18¢ in new technology (6 kwh/lb.) plants. The savings of 9¢ per pound, or $180 per ton, would result in a ten year payback period on investment in new technology capital equipment, based on BPA's estimate of capital costs of $1800 per ton of capacity. This would make it

considerably more attractive than under current pricing which yields a payback period of about one hundred years. This simple analysis illustrates how use of average costs instead of the opportunity costs in setting electricity rates discourages development and use of energy efficient technology.

Such an increase in the cost of production of aluminum would adversely effect the competitive advantage of aluminum plants in the Pacific Northwest unless incremental energy costing is universally adapted. Presumably, the region's aluminum plants are competing with aluminum plants located in other areas of the country and in other countries. Many of the plants in other locations are owned by the same corporations which own the Pacific Northwest plants. Corporate decisions on the operation of these plants are and will continue to be made in the best interests of the shareholders. If Pacific Northwest plants lose their competitive advantage, the corporate decision makers will either close them or modernize them.

A rise in the market price of aluminum due to pricing electricity at its opportunity cost may be beneficial to society and the economy as a whole. A price increase caused by inclusion of full economic costs would tend to reduce those uses of aluminum which are uneconomic, provide significantly greater incentives to recover and recycle used aluminum, and encourage modernization of aluminum plants by incorporation of energy efficient processes. Less new electricity generation would be required because the energy efficient aluminum plants would use less and hence free part of their former consumption for other consumers. Since the aluminum industry would be paying the full economic costs for the electricity it consumes, many of the arguments which have been levied against the industry for using too much valuable electricity would no longer be applicable; the energy intensive jobs in the industry would be better protected against cutbacks in period of drought, and the scarce capital and energy resources of the region and the country would be used to considerably better advantage.

Although beneficial in the long term, the transition to incremental electricity pricing should not be abrupt. Studies are necessary to identify potential problems caused by the transition and appropriate methods of mitigating them, and to facilitate long range planning by users of electricity BPA should take a leading role in analysis of this problem.

The role EIS makes continued reference to the benefits to the region of having a market for interruptible power because it serves as a surrogate for a portion of the required level of reserves to provide generation reliability 20 to the system. According to the industrial firm rate schedule, only 25% of the power delivered to the Direct Service Industrial customers can be cut off in periods of critical water. During the drought of the past year which resulted in all time record low flows in the Columbia River Basin, the industry was able to purchase replacement energy for almost all the year's interrupted electricity. Overall cutbacks in the industry ended up at around 8% rather than 25%. This indicates that resource planning based upon critical water does not incorporate all of the resources which are available under such conditions. Too much energy is sold as interruptible. Additional analysis appears necessary to determine the optimum classification of the region's energy resources into firm and interruptible energy supplies. The impact statement should do more than describe interruptible power sales as beneficial. It should carefully determine the amount of benefit and how the benefit should translate into rate reductions from the firm rate.

COMMENT 7 PLANNING FOR RELIABILITY

This comment refers to:

Part I, Chapter II-B, The Role of Reliability in the Pacific Northwest Power System, Part 3, Reliability Criteria in the PNW Power System

Appendix A, Chapter II-A, Methods Used to Plan New Generating Resources Part 2a, PNUCC Planning Goals

Appendix B, Chapter III Transmission Reliability, Part B. 6, General Economic Considerations in the Cost and Worth of Reliability, and Part D, Description of Alternate BPA Reliability Criteria and Their Impacts or Consequences

Appendix B, Chapter X, Part A.2, Location of Major New Generation Sites Near Urban Load Centers

Reliability Analysis

As with other areas of concern in the Role EIS, the discussion of reliability is scattered throughout the five volumes with some lack of continuity among the various entries. Included in this is a survey in Appendix C, Chapter 21 IV, part I., of the rapidly growing literature on the costs of outages, and the value of reliability. This literature, which has appeared in respected economic and utility industry journals, explores the position that reliability is a valuable aspect of electrical service and like any other valued commodity, more reliability is better than less reliability. It is however, subject to the law of diminishing returns, and the decreasing value of incremental levels of reliability must be weighed against the cost of such increments to arrive at an optimal level of reliability.

This is a particularly important issue in the electrical industry, as reliability is provided by building excess or redundant capacity, so that equipment failure or malfunction will not serve as a constraining factor on service to ultimate consumers. Excess capacity is provided in generation, transmission, and distribution. Although outages can occur at any time with great variation in potential load displacement, present reliability planning prepares for "worst case" contingencies, that is, sufficient excess capacity is provided so that even peak period outages will not disrupt load. This means that the degree of redundant capacity on the average, is far greater off peak than would be required by the reliability criteria. Redundant capacity is also extremely expensive. If 15% excess capacity for reliability reserves is required for generation, then West Group peak loads of 24,000 MW requires 3,600 MW of reserves. At current construction costs this means about $3.6 billion in investment is designed to provide backup for generation which is down during peak periods. Not only does reliability planning consider peak loads, but in considering energy requirements "worst case" planning both evaluates hydro capability under critical water conditions, and includes interruptible loads in the total load for which reliable service must be provided. Interruptible loads are included in the total load for which generation must be planned and constructed, even though interruptible customers pay a reduced rate because they can be interrupted. Thus interruptible customers are probably not paying their share for having their loads included in the total load for which generation is planned. This seeming contradiction in not discussed in the Role EIS. Including interruptible loads in total loads also makes future power "deficits" seem worse than they really are. Some projected deficits are not deficits for customers which pay for the privilege of receiving firm power. For example, in the discussion of power curtailment policies in Appendix C, Chapter II, part 3.7, the West Group forecast of loads and resources through 1987 shows energy deficits every year. In five of the 10 years there are no deficits if interruptible loads are removed even in critical water years.

If one considers the probable time pattern of outages, this "worst case planning" is even less attractive. Thermal generation may go down at any time. If the outage occurs during the runoff period when water is being spilled or when surplus sales to California are taking place, there will be no loss to the system. Hydroelectric outages during periods of low flow will similarly have a reduced impact on the system. Any outages which occur during slack season for the Pacific Southwest can be at least partly offset by purchasing power from that region. The desirable level of excess capacity in the system will be overstated if reliability planning does not consider these factors. It does not appear to do so. Similar arguments hold for transmission reliability. Transmission line outages are mitigated by the loop characteristics of the transmission system together with the excess capacity on each segment of the system. Energy problems are irrelevant here, so the impacts of an outage will be dependent upon the load conditions when the outage occurs. An outage which occurs at a slack time will put much less strain on the transmission system than one at peak load conditions. Depending on the load duration characteristics of the local system, peak conditions might occur only a few hours a year. An area needing reinforcement according to the usual reliability criteria might in fact need it only for an outage occurring during, say, the peak 10% of the year, while an outage during the remaining 7,884 hours of the year would cause no problems. Depending on the timing of the peak and the likely cause of outages this situation might or might not deserve reinforcement.

Various studies have attempted to place a value on reliability and determine optimum reliability levels. Some of these studies are discussed in Appendix C of the Role EIS. However, these studies are dismissed because measuring costs and benefits is beyond the "present state of the art." While this conclusion may be debatable, the lack of an "accepted" method for objectively determining optimum reliability levels does not justify the EIS treatment of reliability standards. The essence of the EIS discussion of existing and alternative reliability criteria is found in the following quotations:

> They (i.e. the existing reliability criteria) represent engineering standards and practices accepted by the industry and reflect the state of the art. (Appendix B, p. III-22, l. 27-29).
>
> The existing reliability criteria reflect economic considerations of how much insurance can the Pacific Northwest reasonably afford against the likelihood of outage occurrences. (Appendix B, p. III-25, l. 25-27).
>
> If this reduced reliability criteria were to be adopted, it would impact major load centers nearly every year. Loads would have to be

> dropped, and cascading effects could very well spread to regional blackouts. (Appendix B, p. III-26, l. 3-5).
>
> We believe that the impact of reduced criteria would be severe. (Appendix B, p. III-26, l. 19-20).

In these statements BPA is simply telling the reader that the existing reliability criteria are good. Changing them would be bad. No attempt is made to explain the "economic considerations" used by BPA and the industry to determine "how much insurance can the Pacific Northwest reasonably afford..." No attempt is made to explain what "reasonably afford" means. Indeed, the reader is given no idea what the costs of the insurance against outages is. Because electricity customers do pay for reliability, they should be able to review the logic behind the reliability criteria. If the specific criteria are determined arbitrarily, or on the basis of experience, or by some analysis, the method of determination should be explained. Mere statements of BPA belief does not satisfy the purpose of impact statements.

COMMENT 8 ON THE RELATIONSHIPS AMONG PLANNING, PRICING AND FORECASTING

This comment relates to the following sections:

- Chapter IV The Future of Electric Power Development in the Region--Power Demand Section A. Load Forecasting, Subsection 1. The Purpose of Load Forecasting
- Chapter VII. B. I. Methods of Power Acquisition, Resource Planning and Operations, subpart c. Long Range Planning
- Chapter IX.B. Mitigating Measures Applicable to Marketing
- Chapter XI Irreversible and Irretrievable Commitment of Resources. Part B. Regional Planning Considerations
- Appendix A. IIA Methods Used to Plan New Generating Resources
- Appendix C. Chapter IIB3 and IIB5 Determination of Wholesale Rates and Retail Rates.
- Appendix C, Chapter IIIB3 and IIIB5 Alternative Wholesale Rate Concepts and Alternative BPA Retail Rate Policies
- Appendix C, Chapter IVG Impacts from Different Rate Structures.

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Past and current practice in the utility industry, accepted and abetted by BPA, is to forecast the growth of electricity consumption based on extrapolation of past trends with greater or lesser degrees of sophistication in forecasting methodology practiced by different utilities. In planning the construction of new generating resources, the forecasted consumption of electricity is compared with the ability of existing resources and those already planned or under construction, to generate electricity; after this comparison, the difference between forecast consumption and planned and existing generation is used to indicate the need for new resources. This planning method is based upon what is seen as a legal requirement labeled "utility responsibility." This means that a utility has a legal responsibility to provide sufficient electricity to anyone who wants it in the utility's service area. The utility industry has operated reasonably well under these procedures in the past, but the procedures are currently coming under increasingly intense scrutiny by the public, economists, and Public Utility Commissions. The criticisms of this planning methodology, to say nothing of the impacts of the methodology and alternatives to it, are simply not treated in the Role Impact Statement.

A major objection to the use of the industry planning methodology is that it has been, and continues to be, tied to the use of average cost rather than marginal cost pricing. This use of average cost is also the reason that the practice worked tolerably well for the industry over the major part of its history. For most of the period since large scale electrical generation and distribution became feasible, the marginal cost of new generation has been less than the average cost of existing generation in the utility industry. By charging an average cost based price, which slowly droppedover time, the growth of electricity consumption that was forecast and facilitated, was also economically legitimate. The uses to which consumers were applying electricity

were those which they valued at least as high as the price they were paying, which was somewhat higher than the economic cost of the resources going into the production and distribution of that electricity. As will be explained below, because the marginal cost of electricity is now higher than the average cost, this situation is now reversed. The uses to which electricity is put now include uses the values of which are less then the economic costs of the resources going into the production and distribution of the electricity. Too much electricity is being produced; too many generating units are being planned and built. Society would be better off, in terms of individual income and welfare and in terms of Gross National Product, if electricity was properly priced and used, and the resources which would otherwise be used in producing and distributing electricity were devoted to other purposes.

Economic Theory and Optimal Resource Use

Conventional, as opposed to Marxian economic theorists have developed over the past two hundred years, a series of precepts describing conditions necessary for the optimum allocation of resources. These precepts may be summarized by the following:

> The marginal value to the consumer of a commodity should be equal to the marginal opportunity cost of the resources used in its production.

Consider the converse. If consumers place a marginal value on the use or consumption of a good which is higher than its opportunity cost, then the value of the goods foregone by devoting more resources to the greater production of that good, would result in a net increase in consumers well-being. Alternatively, if the marginal valuation placed by consumers on the use of a good is less than its opportunity cost, then the reduction in welfare associated with reduced production would be more than offset by the concommitment increase in the output of other goods.

The same question may be examined from another perspective. If society is considering the construction of a facility to produce a commodity, the question should legitimately be raised whether the benefits of building the facility will outweigh the costs of constructing it. In the absence of any external benefits of the plant other than those received by purchasers of its output, the marginal value of the benefits would be the discounted present value of the product of the output of the plant times the price at which the output is sold, because consumers will adjust their purchases of the good until the marginal value of them is no greater than the cost of an additional unit. The cost to society of building and operating the plant is the marginal value of the goods that could be produced if the plant were not built, but which will not be produced because the resources are being used to build and operate this particular plant. The opportunity costs of building the plant may be represented by the discounted present value of the capital and operating costs of the facility. If the benefits are greater than the costs, then the plant should be built, for doing so will increase the net welfare of society.

Now consider the effect of the use of average cost pricing of electricity in a time when the marginal cost of new generation is considerably higher than the average cost of old resources. From either of the two perspectives offered above, scarce resources are being misallocated.

The average consumer in the Pacific Northwest is a customer of a utility with predominently hydroelectric resources. With an average cost based price of between 10 and 20 mills per kilowatt-hours (kwh). In making decisions which relate to the use of electricity or substitutes for it, the consumer will rationally use the cost to himself to weight against the benefits of various alternative courses of action. Such decisions may range from a residential consumer deciding how much or whether to insulate his house, to the decision by a builder to install baseboard electric heat as opposed to gas heat or even solar heat, to the decision by an aluminum refiner of whether to invest in a new, electricity-saving technology. In each case the decision will be based on the marginal cost to the consumer, which is the price he pays for the electricity. The Seattle City Light customer may adjust his use so the marginal value to him of the electricity he uses will be around 10 mills per kwh. For the large direct service industrial customer of BPA, for example an aluminum refinery, the marginal value of electricity will be around 3 mills per kwh. These marginal values should be compared to the marginal costs of electricity to decide if the optimum amount of electricity is being produced and consumed.

What is the marginal cost of electricity? In an energy-constrained system like that of the Pacific Northwest, as opposed to a peak-constrained system consisting primarily of thermal generation, any customer who uses electricity is putting a demand on the system to invest in new thermal generation. The economic cost of electricity in such a system is the marginal opportunity cost of electricity generated from new thermal resources. Considering only generation costs, the marginal cost of electricity is about 30 mills. Including the costs of transmission, distribution, metering, and administration will raise the marginal cost even higher. If the full marginal cost of electricity is, say, 40 mills, and the marginal value to the consumer is as low as 3 mills, we can properly conclude, based on economic theory, that resources are being seriously misallocated.

This should not necessarily lead to the conclusion that an immediate restructuring of electricity prices is appropriate. The transition from average cost to incremental pricing may pose problems for current users that should be carefully considered. The transition should be managed to facilitate long term planning by all users so that they can adapt to the changing structure. Analysis of this issue is crucial; it is not considered in the Role EIS.

Consider now the planning methodology used by BPA and the utility industry in the Pacific Northwest. Planning in this region for new generation is conducted by the PNUCC. This body compiles forecasts of consumption from the utilities in the region. Such forecasts are based on the amount of electricity that will be consumed with a continuation of average cost pricing methods. We can be assured, therefore, that a significant part of that consumption is for purposes that will be worth less to the consumers than the true economic value of the electricity. Estimates given in Appendix C of the Role EIS in the chapter on Impacts From Alternate Rate Structures, indicate that consumption of electricity in the region in the year 1994 by customers of public agencies which buy from BPA would be reduced from 151 billion kwh's with continued average cost pricing to 98.7 billion kwh's if BPA used marginal cost pricing. We have no basis for extrapolating to the use by customers of private utilities, but this indicates that about one third of the electricity

that will be used by BPA customers in 1994, for which generation is being planned, will be for uses which are worth less than the true economic cost of the electricity. Planning which follows legitimate economic principles should ask the question: before a decision is made to commit resources to the construction of a new plant, will society value the output of the plant sufficiently to outweigh the costs of the resources that will be required to build and operate it? It seems likely that if such a question were asked, fewer plants would be built than otherwise.

Appendix A of the Role EIS contains a Chapter IV, "Alternative Methods of Power Acquisition and Operation." There is no section in this chapter, and no section in any other chapter which deals meaningfully with the issue of alternative methods of resource planning. The above discussion demonstrates that this lack is a singularly glaring one. There is scattered discussion of marginal cost pricing and other alternative pricing methods. There is ample discussion of forecasting methods in use and the alternative methods available. The discussion of planning, however, is constrained to a discussion of the methods currently used. Nowhere is the question asked, much less discussed, whether consumers value the additional power from a planned resource highly enough to justify building it. Electricity consumers of the region are never given the chance to express their feelings on this, and the EIS does not contain sufficient information to make a reasoned judgement on just how many plants should be built to bring a proper balance between demand and supply. The reliance on the phrase "utility responsibility" is an improper abdication of the need to examine this issue. If plants are built to serve average cost based price demands that would not be necessary using incremental pricing, an irreversible and irretrievable commitment of resources will occur, including a commitment of capital on which a return will have to be paid by electricity consumers. The final EIS should address this alternative planning methodology.

COMMENT 9 MONTANA IMPACTS

The Bonneville Power Administration's Draft Role Environmental Impact Statement fails to adequately describe and analyze the environmental impacts of BPA's present and future activities on the coal supplying regions of eastern Montana and Wyoming; the EIS contains virtually no analysis regarding these areas, despite BPA's own statement in its advertisement for hearings in Billings, Montana: "Future energy decisions in the Pacific Northwest, particularly generating decisions, have significant implications for development of coal fields in eastern Montana and Wyoming". 23

In contrast to this acknowledgement, the EIS states: "The study area (for the EIS) is defined as Oregon, Washington, Idaho and that part of Montana west of the Continental Divide. It is within this region that the most significant impacts from a regional energy program will likely occur" (Part 1, Chapter III, p. 1). It is from this initial erroneous definition of the scope of the study that many of the defects to be discussed subsequently arise. The scope of the EIS must be expanded to include all of Montana and Wyoming, and these areas must be analyzed as a subregion in discussions of the existing environment and impacts of the proposed action. The second sentence of the statement is simply incorrect; almost all potential activities of BPA (short of going out of business) could have the following potential impacts on eastern Montana and Wyoming: 1) increased mining of coal; 2) pressure to construct more minemouth coal-fired generating plants; 3) expanded energy transportation systems (railroads, transmission lines, coal slurry pipelines); 4) a reduction in the states' role of regulating and mitigating the adverse environmental impacts associated with energy related development.

Coal Mining

The Draft EIS states:

> The preponderance of coal or uranium to supply future generating plants in the Pacific Northwest will have to be obtained from outside the region... However, the extra-regional impacts are not discussed here due to the practical limitations on the size and scope of the EIS. The reader is encouraged to examine the existing studies which specifically address the impacts of these processes... (Part 1, Chapter V, p.1) 24

This approach results in the failure of the EIS to analyze coal supply impacts as they relate to BPA's activities. The need is not to assess the general environmental impacts of coal mining on land; it is to assess the effects BPA's activities might have on coal mining areas. This must be done, not by "existing literature", but by the Draft Role EIS.

Minemouth Generating Plants

As with the issue of coal mining, the incorrect definition of the proper scope of the EIS results in a failure to consider the environmental impacts of potential minemouth generating plants which could be located in eastern Montana and Wyoming to serve the energy demands of BPA's traditional service areas.

The existence of the Colstrip and Jim Bridger power plants and the role they play in the present Pacific Northwest power picture demonstrates the arbitrariness of excluding such consideration in the Draft Role EIS.

Discussions of coal-fired generating plant locations generally revolve around two primary possibilities: the load center or the minemouth. The Draft Role EIS itself offers sufficient reason for a detailed analysis of the minemouth generating possibility: "Contractual agreements, particularly net billing, facilitates development of nonfederal power resources." (Part 2, Chapter VII, p. 24) "Power from sources other than hydro generation is necessary to increase regional firm capacity." (Part 2, Chapter VII, p. 25) The latter statement is an especially cogent argument for detailed analysis of minemouth generation in view of the proposed action the EIS is supposed to address: For the BPA "to continue to direct its programs, functions and efforts toward the achievement of its mission of assuring a viable electric energy system in the Pacific Northwest, while balancing economic, technical and environmental considerations." (Part 2, Chapter VIII, p. 1)

BPA's involvement in nuclear and coal-fired power plants to meet its perceived "mission" was a primary reason the Draft Role EIS was prepared at all; the environmental impacts of that involvement cannot be adequately addressed without a careful analysis of areas which might be potential minemouth power plant sites.

Energy Transportation

Assuming that the Pacific Northwest's power demands could be served in some way by coal from the Northern Great Plains, whether from coal converted at load center or electricity generated from minemouth plants delivered via the BPA transmission system, the necessary transportation systems will have a significant effect on eastern Montana and Wyoming.

Appendix B, Chapter IX, "Forecast of Proposed Transmission Requirements" is a good example of the failure to adequately assess these impacts. This Chapter, which is supposed to describe "major transmission facilities that could be required between now and 1996", does not even mention the transmission lines which will be built from the Colstrip plants to the BPA station in Hot Springs, Montana. It seems obvious that these facilities and their associated environmental impacts are intimately related to BPA's present and future activities, as vividly illustrated in the BPA/Forest Service preliminary report, "Potential Energy Corridor Requirements for the Pacific Northwest."[1/]

The other transportation alternatives and their associated environmental impacts are not evaluated at all beyond cost comparisons (Part 2, Chapter V, p. 41) and a few scattered descriptive paragraphs.

State Authority

Although the issue of the Statement's failure to evaluate the impact of the proposed action and alternatives on state authority is discussed at more length elsewhere in this comment, it deserves some mention under the subject of impacts on Montana. As should be acknowledged, but is not, in the EIS, the 25

State of Montana has devoted very substantial effort to dealing with its position as a potential energy supplier to the Northwest and to the nation. This effort is reflected in its facility siting law, its mining and reclamation laws, and its active participation in energy policy discussions at the national level. Should these laws be weakened by BPA's activities, the environmental impact on Montana would be very significant. These potential impacts are inadequately discussed in the EIS; the primary discussion consists of the following:

> As the regional entities continue to cooperate in planning construction and operation of the power supply system, and to the extent that such cooperation leads the region closer to the one-utility system, there will be a commensurate loss of local control, accordingly, a greater potential for the system to be unresponsive to subregional environmental problems. Restated, the regional economic benefits of an integrated power supply system may be accompanied by adverse effects on the localized government. (Part 2, Chapter VIII, p. 2)

The Statement is descriptive rather than analytical, and entirely fails to offer the kind of rigorous evaluation of environmental impacts required in an EIS; in addition, there is no analysis of how such impacts can be mitigated.

Other sections of the statement likewise indicate that the states and their role in energy planning were almost entirely ignored:

> Decisions on the number of new generating facilities required to meet the region's loads would be based upon forecasts compiled by Pacific Northwest utilities in conjunction with BPA. (Part 2, Chapter XII, p. 14)

Our concern over loss of state authority in helping to determine the energy future of the Northwest is not, we believe, myopic parochialism. A Nuclear Regulatory Commission study paper examined the issue of improving the regulatory process of power plant siting, which included both nuclear and conventional plants:

> ...We have identified the broad outlines of an effective regulatory process. Its primary thrust is on a system in which Federal emphasis is on determining the <u>effect</u> of proposed actions in which States have an increasing and more positive role in determining the <u>acceptability</u> of actions within their purview... Another key element would be the acceptance by Federal agencies of the State determination of need for power as binding on the Federal review process. [2] (emphasis added)

Unlike the NRC report, the Draft Role EIS is almost bereft of any mention of the states' role in energy planning. This failure to cope with existing political institutions and their energy-related regulations, gives the entire report a rather Alice in Wonderland feeling. One simply cannot discuss realistically, the role of BPA in a political vacuum. While the word <u>coordination</u> occurs frequently in the Statement, one is left uncertain about what parties will be involved--one must assume that BPA contemplates its continued coordination with utilities while largely ignoring states, particularly Montana and Wyoming. As mentioned already, this thrust has very serious environmental ramifications which must be fully addressed in the final EIS.

Closely associated with the issue of the state's role in energy planning, are the issues of public participation and public accountability. Again, the Statement acknowledges the possible adverse impacts of BPA's proposed action, while failing to rigorously analyze the problem or offer mitigating measures;

> There are long-term costs associated with a decision to plan cooperatively. Planning on a regional basis isolates much of the process from the influence and control of local citizens, who can be useful contributors of ideas and opinions. Planning for regional power needs may cause nuclear and other large plant options to be favored over smaller plants and alternative sources, such as solar or wind energy, which in some applications are oriented toward small scale applications. The alternative source may have fewer impacts on air and water quality, but at present these methods are more costly than nuclear or coal-fired generation. On the other hand, regional planning collects resources (funds, equipment and personnel with technical expertise) which can more easily be applied to development of alternative energy techniques (such as wind or solar power) than would be possible under fragmented local planning. (Part 2, Chapter XI, p. 2)

It might be added as an aside that the latter portion of this statement is pure hypothesis: There is no evidence that BPA has any real desire or commitment to use its "expertise" to develop alternative energy techniques. "Fragmented local planning" in the guise of state activity has shown, at least in Montana, a much higher commitment to alternative energies than BPA has demonstrated in the past or in this Draft Role Environmental Impact Statement.

This failure to adequately deal with public participation seems to run directly counter to the thinking of others who are concerned with energy policy:

> ...Coping with the shortfall between domestic energy production and consumption is intimately tied to (a) broadened scope of participation. Only when ways are found to accommodate the varied interests that will be participating in decision making will the energy crises be resolved.[3] (Kash, p. 5)

> The study team thinks it imperative that we settle on a national policy which allows the public early access to long-term utility plans at the local and regional level, and an opportunity to comment and make its views known early in the process. In the past, many decisions affecting people's lives and property were made privately by utilities and by some regulators without adequate public participation or comments. In the future, we believe those decisions have to be made in a more public fashion, in a form to which the public has early access and some likelihood that its views can influence decisions. We conclude therefore that Federal law should encourage the development and operation <u>by States</u> of a multi-state mechanism for exposing to the public the long-range plan of utilities for sites, for transmission corridors and for facilities.[4] (emphasis added) (NRC p. 1)

Public participation, in the form of individual and private organization involvement, has been intense, and for the most part, very beneficial in Montana's development of state energy and environmental policies. We cannot endorse a proposed action which does not thoroughly explore and offer alternatives for enabling this kind of involvement to continue. In our view, the BPA and the EIS must explore ways in which the state role in energy planning and as a mechanism for public participation and accountability to the public can be strengthened within a regional framework.

In summary, the probable impacts of BPA's proposed action on eastern Montana are either not discussed at all, or are mentioned only in passing. Where they are mentioned, their treatment is cursory and descriptive. Rigorous analysis and discussion of mitigating alternatives are nowhere to be found.

References for Comment 9

1. Potential Energy Corridor Requirements for the Pacific Northwest - Long Range (1985-2020) - Report to the Joint Bonneville Power Administration-Forest Service 1977 Meeting, April 27-28, 1977, by Joint BPA/FS Group No. 1

2. <u>Improving Regulatory Effectiveness in Federal/State Siting Actions</u>, Office of State Program, U.S. Nuclear Regulatory Commission, #NUREG-0195; May, 1977, p. 1-5.

3. Kash, D on E and others, <u>Our Energy Future</u>, University of Oklahoma Press, Norman, Oklahoma, 1976.

4. See Note 2.

COMMENT TO BPA FUTURE ROLE

This comment relates to Part 2 The Role of BPA, Chapters VII through XII

In Volume 2 of the EIS, BPA proposes as its future role "...to continue to direct its programs, functions, and efforts toward the achievement of the mission... [to] ...assure a viable electric energy system in the Pacific Northwest while balancing economic, technical, and environmental considerations." It is difficult to find fault with this general statement of general goals. 26
Substantive criticism is possible only when the BPA role is defined in terms of specific policies and programs for implementing the three basic responsibilities which BPA desires to retain: marketing of power from the Pacific Northwest Federal hydro generating projects; coordinating the operation of the region's generation and transmission system to realize the benefits of a single system (or "one-utility" concept); and constructing and operating at least the "backbone" of the region's transmission system.

Volume 2 also discusses various "probable and improbable" alternative roles for BPA ranging from dissolution of BPA by Congress to creation of a Columbia Valley Authority similar to the Tennessee Valley Authority which would establish BPA as a utility with full authority to purchase and build new generation to meet electrical demands. Two more specific proposals for the BPA future role have been introduced as legislation before Congress, the so-called "PNUCC Bill" (S.2080) and the "Weaver Bill" (H.R. 5862). These two bills are not analyzed as future alternative roles in Volume 2, but because of their potential to become law and hence fix the BPA role, and because of level of detail inherent in these proposals, both should be analyzed in detail in the final impact statement.

To critique and analyze any or all of these alternative roles in detail should be a function of the impact statement rather than comments on it. Also, the final role of BPA will be determined as a result of political and technical interaction and compromise among the numerous special interests and affected entities within and without the Pacific Northwest Region. For these reasons, no attempt will be made here to compare the various alternatives and design the optimum future BPA role; rather Montana's interests and prerogatives will be discussed along with the minimum acceptable requirements for a BPA role and regional energy organization.

Montana's Interests

Throughout the Role EIS, the BPA touts the benefits of operating the electrical generation and transmission system as a single utility. These benefits may indeed be real, but for Montana the single utility system terminates 75 air miles east of the Continental Divide, the boundary of BPA's service area. Thus the current and projected BPA roles maintain one utility system and two states of Montana: a western Montana state considered part of the Pacific Northwest which will be served by BPA and benefit from BPA's role, and an Eastern Montana state which will provide energy to the Pacific Northwest but remain separate from it and which will not be served by BPA.

Chapter IX of Appendix B, BPA Power Transmission entitled "Forecast of Proposed Transmission Requirements," attempts to make such a forecast. However,

future transmission requirements can not be estimated without some idea of the location of the generation plants. The Chapter therefore includes the "hypothetical situations" which show different distributions of the total 1996 thermal generation required according to the PNUCC forecasts. These "hypothetical situations" include from 7,000 to 22,000 MW of "Eastern Thermal", or coal fired generation located in the coal fields of eastern Montana and Wyoming. The associated transmission requirements vary from at least two 500 kV lines to at least three 1100 kV lines across the Rocky Mountains. Evidently the state of Eastern Montana (and Eastern Wyoming) will be expected to make a significant contribution to the Pacific Northwest, a contribution facilitated by the construction of transmission lines by BPA to integrate the "Eastern Thermal" into the Pacific Northwest transmission system.

Although this significant role is expected, the EIS makes no attempt to discuss the impacts of this role on eastern and western Montana; nor how all of Montana could have meaningful input into BPA and Pacific Northwest energy planning and policy decisions; nor how the entire state of Montana might be compensated for bearing the burden of producing energy which will benefit the Pacific Northwest. The EIS ignores these questions presumably on three grounds:

1) BPA does not now and does not advocate building and operating generation units in the future;

2) transmission line availability does not determine generation location (Appendix B, p. X-3); and

3) specific impact statements will be prepared on specific generation and transmission projects.

These three arguments are not sufficient justification for pretending the EIS responsibility terminates at BPA's service boundary. Whether or not BPA wishes to construct generation is irrelevant. Alternative roles are discussed which could allow or mandate BPA to construct or underwrite the financing of such plants or to guarantee the purchase of the output of thermal plants located outside the Pacific Northwest for a regional power pool.

Even under the existing BPA role, BPA transmission line construction may facilitate certain generation location. Although BPA has in the past and continues (p. X-3 of Appendix B) to argue that transmission decisions are somehow separate from generation decisions, they cannot be so separated. The economic and environmental costs of a coal-fired plant located in eastern Montana to serve loads west of the Cascades must include the economic and environmental costs of the transmission lines necessary to transport the electricity from the source to the load center. If all of the costs associated 27
with the construction and operation of transmission lines are included in the analysis, load center rather than minemouth generation may be the optimum location. In circumstances where the costs of transmission of electricity or shipping coal are comparable, transmission line construction by BPA might tip the scale in favor of minemouth plants because federal facilities are not subject to state and local taxes or because of BPA's ability to acquire or use existing transmission rights-of-way.

The future preparation of site and project specific impact statements also does not justify ignoring the problems created by the divided Montana because a change in BPA's role or a change in its service area boundaries could help to alleviate the resulting inequities. Alternatives for compensation of areas outside of BPA's service area which supply energy to the Pacific Northwest must be explored in the EIS. One example might be the inclusion of a surcharge in BPA wholesale rates for any energy generated outside the region which is transported into the region by the BPA transmission system. This surcharge could be returned to the area generating the power to compensate for the associated environmental degradation. Additionally, the potential benefits and determents of changing BPA's service area boundary to include all of Montana or all of Montana west of the transmission system break at Fort Peck and Yellowtail should be assessed.

Montana does not object to sharing its resources on a reasonable basis with the Pacific Northwest or any other region of the country. However, no portion of Montana must be forced to bear the burden of resource development without adequate protection and compensation. Any future BPA role or region-wide energy policy must give consideration to this protection and compensation. The Draft Role EIS does not do so, and is therefore inadequate.

Minimum Requirements for a BPA Future Role

In addition to avoiding or mitigating problems resulting from an arbitrary division of Montana, any acceptable regional energy plan incorporating a future BPA role should include the following requirements:

1) Recognition of and respect for state energy policy, energy pricing, and siting authority.

Any regional energy plan must be accountable to the region's individual 28
states, and must not be dictated by the federal government through BPA or by the utility industry through a private group such as the Pacific Northwest Electric Planning and Conservation Organization. State pricing and siting authority must not be pre-empted either directly by federalization of the region's energy generation and transmission system nor indirectly by allowing BPA or a private regional utility group to make commitments on plant location, design, financing, and pricing before seeking state permits, and thereby "steamrolling" state authority. Finally, any BPA future role should include mechanisms for close federal-state cooperation to avoid conducting state and federal studies in series, thereby creating unnecessary delays in constructing needed energy facilities.

2) A rational planning process which reflects the actual cost of energy in terms of economics and environmental impacts and which balances needs and supplies by the most cost effective methods.

The use of renewable alternative energy sources and the potential for reducing demand through agressive conservation must be considered equally with 29
meeting demands by energy generation from nonrenewable resources. Planning to meet forecasted demand should not be based on an average cost approach which undervalues the energy output.

3) Conservation must be a cornerstone of any regional energy policy and BPA's future role. 30

Because of the high economic and environmental costs of energy generation, energy waste is intolerable. Conservation must, therefore, be the foundation for regional and BPA energy policy and not a politically expediant add-on feature.

4) Allocation of federal hydrogeneration and BPA wholesale pricing mechanisms must retain flexibility so that changing conditions in the Pacific Northwest region can be reflected in them.

Fixing energy allocations and pricing mechanisms for long periods such as the 35 year time frame in the PNUCC bill, may in effect freeze existing 31
economic patterns and harm the region's economy in the long term. Guaranteeing a long term supply of energy priced at less than its acutal value to any group of customers, such BPA's current direct service industrial customers, will create a disincentive for energy conservation and process modernization. Fixed allocation patterns may also prevent introduction of new energy-efficient and job-intensive industries from locating in the region. Competition and risk are essential elements of a healthy economy in a free enterprise system. To the extent that frozen allocation patterns and pricing methods eliminate competition and risk, the region's long term economic health may be jeopardized.

5) Any future BPA role and regional energy planning mechanism must be both open and responsive to public input. 32

Implementation of any future BPA role or regional energy plan will require the coopeation and confidence of the public. Such cooperation and confidence will not develop unless the public has meaningful access to the decision making processes in BPA and any regional energy planning organization.

Letter #46

STATE OF CALIFORNIA—THE RESOURCES AGENCY EDMUND G. BROWN JR., Governor

CALIFORNIA ENERGY COMMISSION
1111 HOWE AVENUE
SACRAMENTO, CALIFORNIA 95825
(916) 920-6811

June 11, 1980

Mr. John Kiley
Environmental Manager
Bonneville Power Administration
P. O. Box 3621
Portland, OR 97208

Dear Mr. Kiley:

The following comments on the Bonneville Power Administration Role EIS are submitted by the California Energy Commission staff. They relate solely to issues affecting BPA's relationship with California.

BPA has generally not adequately described the national (as opposed to purely regional) consequences of its actions as they affect exports of surplus energy from the Pacific Northwest to California. The Revised Draft EIS states: 1

> The environmental and socioeconomic effects of the region's existing secondary energy sales on the Pacific Northwest and California are discussed in the original Role EIS. (Revised DEIS, p. 267)

However, BPA ignores a number of factors which have changed substantially since the 1977 release of the original Draft Role EIS. Specifically: 2

- o Domestic oil prices have more than doubled, rising from about $13 per barrel to over $30, and imported prices tripled to about $40 per barrel. This raises incremental energy costs in California from about 20 mills/kWh to 50 mills, and to 67 mills in terms of imported costs. This significantly raises the national value of both surplus hydro and displaced Northwest non-oil thermal power to reduce oil use in California.
- o Events in Iran underscore the need to reduce oil use for national security reasons. The efficient use of the existing intertie thus has national security benefits which were not taken into account in the original Draft EIS. The Department of Energy has undertaken a "coal by wire" program to displace oil in the Eastern U.S.; yet this benefit was not highlighted in this report, and rates for surplus Northwest thermal energy from domestic resources are not consistent with the "coal by wire" program rates.

- o BPA has raised its rates for sales of secondary energy to California by up to 567 percent--from 3 to 3.5 mill/kWh to a maximum of 20 mills. By contrast, Northwest rates rose by less than 30 percent. Thus, even if BPA does not collect the maximum 20 mills on all transactions, higher rate increases to California than to the Northwest are being used to transfer money from California ratepayers to Northwest ratepayers including the aluminum industry. This spares the Northwest the full burden of paying for the net billing arrangements of the hydrothermal program. By cushioning the rates in this manner, BPA gives Northwest ratepayers inaccurate price signals, and conservation actions are undervalued and discouraged.

  It also shifts the benefits of any future intertie arrangements from California to the Northwest, thus making future interties less financially justified to the California utilities who must pay most of the cost unless BPA absorbs a larger cost share of new lines.

Thus, to summarize, the value of the existing intertie and its required expansion to the Northwest, to California, and to the nation as a whole has increased dramatically since the release of the original Draft EIS. These changed circumstances should be recognized in the revised EIS.

More important than the understatements of the benefits of the current intertie between the Northwest and California is the underestimation of the losses resulting from inadequate interconnection capacity for exporting the region's surplus energy and capacity. Correct estimates are vital to a proper assessment of BPA's and the Southwest utilities' future investment programs. The revised Draft EIS states: 3

> One effect of displacement would be to reduce the environmental impacts associated with thermal operations...If energy surpluses could not be marketed, the only likely recourse would be to idle the most expensive and environmentally harmful plants in the region...It is highly unlikely that any absolute cost savings or rate benefits could occur, however, because savings in operating costs probably would be more than offset by the fixed costs of idle capacity. (Draft EIS, p. VI-271).

This passage may partially describe the impact on the Northwest of failure to market surplus energy, but it does not discuss the key issue--the millions of barrels of additional oil burned unnecessarily in California for lack of adequate transmission capacity to deliver the surplus energy to California.

This is not merely a hypothetical issue. Northwest thermal plants have operated in the past at about a 50 percent capacity factor in average or good water conditions such as 1976 or 1978, compared to 70 percent in the drought year of 1977 (See Table 1). Hydropower from British Columbia cannot be marketed through the Northwest to California in good water years because of limited intertie capacity. Even in the spring of 1980, a year in which water flows are estimated at only about 82 percent of median, Northwest Power Pool data indicate that Northwest public and private utilities are reducing domestic resource fired thermal output for economic reasons and the inability to deliver it to California due to intertie capacity limitations.

R. W. Beck and Associates' recent study (the summary of which is attached for the record) indicates that on the basis of extremely conservative assumptions, that an average 2.8-4.1 billion kWh per year, displacing 4.7-6.8 million barrels of oil, could be delivered to California economically if 2400 to 4400 MW of new Northwest-Southwest intertie transmission capacity were constructed. (See Table 6 of the Staff Comments). The inability to market this additional secondary energy to California will have severe socioeconomic and national security impacts and will add to the air pollution in some of the nation's most stressed air basins. We hope that these impacts will be included in the Final EIS.

I appreciate this opportunity to submit comments.

Sincerely,

RUSSELL L. SCHWEICKART
Chairman

Attachments.

(Included with this letter was an attachment: Summary Report of the Analysis of Expansion of the Pacific Northwest-Southwest Intertie System, California Energy Commission, April 1980.)

Table 1

AVERAGE CAPACITY FACTORS FOR THERMAL STATIONS
BASED ON WATER CONDITIONS

	Hanford, Centralia and Trojan		Jim Bridger and Dave Johnston	
Month	Average to Good Water Conditions	Drought Conditions	Average to Good Water Conditions	Drought Conditions
January	74.0%	72.8%	68.5%	79.5%
February	65.4	84.0	74.7	86.5
March	58.2	70.8	66.9	69.7
April	50.1	85.8	61.5	64.8
May	29.1	39.4	48.7	60.7
June	15.8	55.2	51.2	65.7
July	15.0	55.2	54.3	74.8
August	48.5	47.7	65.6	72.4
September	53.8	54.1	64.0	58.1
October	63.2	81.1	66.8	65.0
November	63.6	90.9	72.9	82.8
December	58.9	88.8	73.2	77.8
TOTAL	49.1%	68.6%	63.4%	71.4%

Drought conditions are defined as December, 1976 to November, 1977. Other water conditions are defined as the remainder of the 1974-1978 time period. Data for Hanford, Centralia, and Trojan is based on January, 1974 - September, 1978. Trojan is included in calculations from September, 1976 to April, 1978. Data for Dave Johnston and the Pacific Power and Light portion of Jim Bridger is based on January, 1975 - September, 1978.

Source: California Energy Commission, Constructive Alternatives to the Bonneville Power Administration's Proposed Rate Increase (November, 1978), p. 20.

Letter #47

UNITED STATES DEPARTMENT OF COMMERCE
The Assistant Secretary for Productivity, Technology, and Innovation
Washington, D.C. 20230
202/377-3xxx 4335

June 12, 1980

Environmental Manager
Bonneville Power Administration
Department of Energy
P.O. Box 3621 - SJ
Portland, Oregon 97208

Dear Sir:

This is in reference to your draft environmental impact statement entitled, "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System." The enclosed comment from the National Oceanic and Atmospheric Administration is forwarded for your consideration.

Thank you for giving us an opportunity to provide this comment, which we hope will be of assistance to you. We would appreciate receiving ten copies of the final statement.

Sincerely,

Bruce R. Barrett

Bruce R. Barrett
Acting Director, Office
of Environmental Affairs

Enclosure Memo from: Malcolm Reid
Environmental Data and Information Service
NOAA

Letter #47 (continued)

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
ENVIRONMENTAL DATA AND INFORMATION SERVICE
Washington, D.C. 20235
Center for Environmental Assessment Services

Rec'd PPIEC
30 APR 1980

April 28, 1980 OA:D242:MR

TO: PP/EC - R. Lehman

FROM: OA/D242 - Malcolm Reid MR

SUBJECT: DEIS 8004.05 - The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System (Revised)

General Comments:

None.

Specific Comments:

Pg. II-1, paragraph 3 - The EIS states that the region of interest is relatively free from violent weather. The EIS would be enhanced if it mentioned the potential for occurrence of the following events: 1

1. blizzards on the Great Plains of Montana and Wyoming;
2. extremely low temperatures of -40°F or less in the inland mountain areas and Great Plains;
3. intense Pacific winter storms along the coast;
4. prolonged periods of fog and precipitation during winter along the coast;
5. extremely deep snow accumulations (normal) in coastal mountain areas above 3,500 feet (msl).

The EIS also states (correctly at the time of printing) that volcanic peaks in the region have been relatively quiescent during their recorded history. The EIS would be enhanced if it were updated to include the recent volcanic eruption of Mt. St. Helens in southwest Washington.

(RF: D. LeComte, D242)

Attachment - DEIS 8004.05

10TH ANNIVERSARY 1970-1980
National Oceanic and Atmospheric Administration
A young agency with a historic tradition of service to the Nation

Letter #48

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION, CORPS OF ENGINEERS
P.O. BOX 2870
PORTLAND, OREGON 97208

OFFICIAL FILE COPY
JUN 16 1980
Referred To
Action Taken
ANS. NO ANS.

NPDPL-ER

12 June 1980

Mr. Sterling Munro
Administrator
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, OR 97208

Dear Mr. Munro:

This is in reply to your letter dated 2 April 1980 requesting comments on the Revised Draft EIS, "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System."

The EIS does not clearly indicate the Corps of Engineers' role with respect to the Federal Columbia River Power System. Our projects that are in the Federal Columbia River Power System were authorized as multipurpose projects of which hydropower is only one function. We, therefore, must take into consideration purposes other than power generation when scheduling the available water in the river system through our projects. The projects are planned, constructed and operated in cooperation with the states and other Federal agencies to provide for maximum utilization of the resource. Further, Congress has directed that in those areas lying wholly or in part west of the ninety-eighth meridian, any such uses must not conflict with any beneficial consumptive use, present or future. Certainly one of the most common consumptive uses from the Columbia River system is irrigation. Accordingly, in the long-range planning studies we must assume that this policy will continue. 1

We do not agree with your statement on page IV-16 that past efforts of State and Federal fishery agencies to coordinate research and management of the anadromous fisheries of the Columbia River and Tributaries have been "only marginal successful," and intimating that only recently have they developed a "renewed interest" in coordinating their activities. The then seven northwest State and Federal fisheries agencies in the late 1950's formed the Columbia Basin Fisheries Technical Committee and this committee has been very successful the last twenty years in the coordination of efforts on the Columbia Basin. In addition, in 1953, the Corps of Engineers with the assistance of the seven State and Federal fisheries agencies established the Fisheries-Engineering Research Technical Committee to study fisheries problems at Corps projects in the Columbia Basin. This committee has been very successful developing measures to reduce the impacts of hydropower projects on anadromous fish and through FY 1979, the Corps has expended approximately $24.0 million on fisheries research. 2

NPDPL-ER
(Mr. Sterling Munro)

12 June 1980

Although many major acceptable hydropower sites have been developed, there still exists a number of undeveloped storage and hydropower sites. As the value of power increases, we feel it is realistic to assume that additional projects will be constructed. 3

Inclosed are comments on specific sections on the Role Statement for your consideration.

Sincerely,

Richard M. Wells

1 Incl
as

RICHARD M. WELLS
Brigadier General, USA
Division Engineer

2

Letter #48 (continued)

Corps of Engineers, North Pacific Division Comments.
BPA Revised Draft EIS "The Role of the
Bonneville Power Administration in the
Pacific Northwest Power Supply System"

1. Page I-12, I-13. This document is incorrect when it states that no new hydropower projects are under construction, authorized or proposed, and that the outlook for more hydropower is dim. We presently have 2 major projects under construction, 2 projects authorized but not under construction, 3 projects recommended for construction and 7 projects under study. It is suggested that this section be revised to reflect this fact. 3

2. Page I-15, para 3. The discussion on past Corps studies omits House Document 531 from the historical representation of past water resource studies relative to hydropower. The following information is provided:

a. Studies of the Columbia River Basin began with the "308" studies of the late 1920's. A general basin plan completed in 1931 and subsequently updated in 1938 established a ten dam plan for regulation of the main stream Columbia River, principally for the purposes of navigation, irrigation, hydroelectric power and flood control. 4

b. A second major review of the Columbia River Basin was completed in 1948. This plan, published as H.D. 531, 81st Congress, established a main control plan for the Columbia River Basin, including reservoir storage and a levee system for flood damage reduction for the lower Columbia River area. Thus, the 1948 study extended the Corps' mainstem Columbia River plan to include a system of reservoir storage on major tributaries.

c. A third major review of the Columbia River and Tributaries was completed in 1961 and published as H.D. 403, 87th Congress. H.D. 403 provides a refinement of basin plans and established a major water plan for regulation of major floods, provided projects for increased hydropower production to meet growing demand, proposed improvement of the Columbia-Snake River navigation system, recommended increased irrigation water supply, and provided the base for negotiations with Canada on development of the Columbia River in Canada. In 1964, these studies led to ratification of the treaty between the United States and Canada for developing four major storage projects in the Columbia River Basin. Three of the Treaty projects, now complete, are in Canada and the fourth project, Libby Dam, is located in the United States.

3. Page I-31. In relation to Alternate 4, we have previously furnished you our comments on regional power legislation as evidenced by the Northwest Power Bill, current House Bill HR 6677, by letter dated 23 May 1980 from General Wells to Sterling Munro.

4. Page III-1. A statement is made in the 3rd sub-paragraph that the hydro system will be used as a backup in the future. On a short term (days to weeks), the hydro system can be used as a backup if a thermal or other power source is reduced or shuts down. However, we do not envision that the hydro system's seasonal operation will change; the backup capability is limited. Suggest some clarification in this area. 5

5. Page IV-8.

a. Sub-paragraph (1)(a). The amount of energy that can be produced from 100 MAF at McNary is in error; it should be in the neighborhood of 6-7 million MWh, not 26.5 million MWh. 6

b. Sub-paragraph (2). The statement that a true storage reservoir project has more capacity than a pondage project is not understood. Suggest some clarification. 7

6. Page IV-15. The third sentence of the next to last paragraph gives the impression that present day technology and costs limit the construction of fishways for hydroelectric projects. We do not concur that technology or costs limit the construction of fishways. The Corps has developed through many years of research an efficient fishway for passage of fish. Cost is not a factor in whether fish passage facilities are provided in Corps hydropower projects. 8

7. Page IV-16. The next to last paragraph is misleading in describing how the nitrogen supersaturation problem has been alleviated. It is true that increased storage and the installation of additional generating units will result eventually in very little spillage of water, thus reducing the supersaturation problem. However, the installed generating and storage capacity has not reached the stage that would permit passing all of the downstream flow through the powerhouses and therefore spilling of excess flows is still required. The Corps of Engineers has developed through considerable research spillway modification called "flip lips" to reduce nitrogen supersaturation and has installed the modification at Corps projects on the mainstem Columbia River and Snake River that were identified as key projects by the fisheries agencies. We suggest the discussion on nitrogen supersaturation be revised to include the above information. 9

8. Page IV-17. The discussion on mitigation efforts does not recognize the artificial propagation efforts of the public and private hydroelectric producers on the Columbia River and tributaries. This is a sizable effort, in that the Corps alone has eight salmon and steelhead hatcheries and two resident fish hatcheries in operation and as many as seven additional hatcheries are being considered under the Lower Snake River Compensation Plan. This section should be revised to reflect the considerable artificial propagation effort in the Columbia Basin. 10

9. Page IV-78. In the discussion of environmental impacts of advance energy sales in the third paragraph we suggest using "minimize" instead of "mitigated." In addition, the parameters for the operating criteria should be clearly identified. 11

10. Page IV-78. The fourth paragraph should be expanded to describe the studies made on environmental impacts of advance energy and also what agency is making the ongoing examination of whether advance energy sales should be reduced to reduce impacts. It seems that there is a conflict in this paragraph. The first sentence states that environmental impacts are acceptable and the second sentence indicates studies are being made to really determine whether impacts are of such a magnitude that advance energy sales should be reduced. We suggest the discussion be clarified and also identify specifically each involved agencies' responsibility. 12

11. Page IV-119. Under hydropower potential, it would be appropriate to recognize the National Hydropower Study. The FERC report referenced is out of date. 13

12. Page IV-123. Impacts of small hydroelectric generation should recognize both adverse and beneficial impacts, not concentrate on the negative impacts. 14

13. Page IV-196 & 197.

a. If note 4 is correct, the Land Use under Small Hydro Generation Table IV-33 should be 1,370 acres. 15

b. The projects listed in note 5 are new projects. In Table IV-33, the heading should be Hydro Additions, not Hydro Capacity Additions, since both Peaking Capacity and Firm Energy are involved. The basis for the acreage figures should be stated.

14. Page IV-275, 1st paragraph.

a. Seasonal fish flows could reduce firm energy in all years, not just low flow years. 16

b. The statement that hydro costs would be higher if project owners had to invest in water quality mitigation is not understood. Further explanation appears warranted. 17

Letter #49

Modern Energy Systems, Inc.

We are dedicated to the development and sale of energy conserving devices for the home and industry

June 12, 1980

Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

Attention: Mr. John E. Kiley
Environmental Manager

Subject: Comments on the April 1980 Revised Draft E.I.S.

Dear Mr. Kiley:

Congratulations are in order for all of those who prepared this document. It is obvious that thousands of manhours were spent with preparation and editing.

First of all, I would like to lend my support for alternative No. 3 or 4 with No. 3 being my first choice.

And now, I would like to consider a general discussion followed by specific comments regarding the use of coal and coal derived liquids and gases.

I urge BPA to expand the scope of energy transmission to include nonelectric technologies that will be available in the foreseeable future. These include: 1

1) Methanol Coal Slurry pipelines,

2) Liquid hydrogen for combustion and fuel cells via super conducting powerline.

My current thoughts on methanol coal slurry pipelines are contained in the enclosed presentation, "Methanol Economy for the Pacific Northwest", which was presented to the Oregon Voice of Energy on May 19, 1980. I shall summarize the points that are relevant to BPA:

1) We will most likely see $200 /KW fuel cells in this decade.

2) Fuel cells can be used to provide:

a) D.C. power for reduction plants
b) Peaking power
c) Electricity for buses, converted diesel-electric train engines, and automobiles.

P.O. Box 03447 □ Portland, Oregon 97203 □ (503) 286-1424

Letter #49 (continued)

3) Methyl alcohol appears to be an excellent liquid fuel that can be readily consumed (via steam reformer to hydrogen) by fuel cells to product electricity.

4) Methyl alcohol can be readily produced from coal at the mine's mouth, and then be used to transport the coal via pipeline. (Here's where electrically related power transmissions come in.)

5) After the methanol has been used to refine and dehydrate the coal, it can be distilled and used to power fuel cells or internal combustion engines.

I don't think that anyone can accurately predict the future load development of electric vehicles. With the price of gasoline and diesel skyrocketing, there is a large incentive to convert to an alternate fuel. We could be very close to a breakthrough in reduced 2
costs and improved performance of battery driven electric vehicles. This could happen by 1985. What will happen to your load forecasting if the majority of new cars are powered by electrically charged batteries in 1985? It may not happen that soon, but how can you be sure? Wouldn't it be prudent to start planning now for the electric propulsion of the foreseeable future?

BPA's load management flexibility will be improved <u>if</u>:

a) Steps are taken to assure that the region has an adequate supply of methyl alcohol.

b) Demonstration projects should be started <u>now</u> to locally prove the economic feasibility of using fuel cells to generate electricity for small vehicles and the large D.C. loads of reduction plants.

c) Encourage the designers of electric vehicles to use fuel cells instead of batteries for medium and long range vehicles.

Evaluation of the proposed methanol economy requires much more than a survey of the literature. Several factors must be weighed in order to determine the overall benefit of the project:

a) Emissions from an advanced coal methanol plant versus a coal gasification and liquification plant.

b) The marketability of potentially carcinogenic coal oils against methanol, which is only mildly toxic.

c) The ability of methanol to dehydrate and refine coal by doner solvent liquification.

d) The relatively low BTU/Lb rating for methanol vs. its naturally high octane rating of 116-120, which allows the use of more efficient high compression engines.

e) Comprehensive cost/benefit analysis.

<u>Page No. III-25,26 - Specific Comments</u>

Regarding BPA's investigation of unconventional and renewable resources, I would like to recommend that BPA carefully watch the progress of fuel cells. 3

Why not locate a demonstration fuel cell power plant at or near the aluminum reduction plants? Since methanol can be easily stored the fuel cells could be used when firm power demands require the use of electricity elsewhere. Eventually, rising costs of thermal power and power from BPA combined with the mass production of methanol from coal may make it economically feasible to use the fuel cells for base loading.

<u>IV-166</u>

Regarding the possibility of coal slurry pipelines in the first paragraph, Northwest pipeline has already proposed the construction of a coal slurry pipeline from Wyoming to the Columbia River to supply coal for power production and export to Asian nations.

<u>Key Point</u> - BPA's evaluations must include the overall energy needs of the region which include electricity (both A.C. and D.C.), 4
liquid and gaseous fuels, solid fuels for export, and the need to minimize the importation of energy.

<u>IV-167</u>

Regarding the costs of coal, I recommend that you add a sentence 5
detailing the estimated cost of coal if delivered by water and methanol slurry pipeline.

<u>IV-169</u>

Regarding the amount of water required for a coal slurry pipeline, you are requested to add a section describing the amount of water
that would be consumed if methyl alcohol or coal oil were used in 6
place of the water. And be sure to consider the fact that dirty pipeline water is a waste product whereas methanol or coal oil can be readily marketed.

<u>IV-178</u>

The following should be added to the paragraph which states that
the burning of methanol would increase the emission of aldehydes: 7

> EPA does not currently restrict the emissions of aldehydes. If methanol is used for the onboard production of hydrogen for internal combustion or to provide electricity via fuel cells, then the emission of hydrocarbons would be negligible.

Regarding the 1½ - 3 pounds of water per pound of coal processed for gasification, I recommend that you add a sentence to the subsequent paragraph addressing the amount of water that would be required to produce methyl alcohol from coal.

Thank you for taking the time to give the above recommendations your thoughtful consideration.

If I can assist you with any questions you may have, please don't hesitate to call me at 226-5303.

Cordially,

MODERN ENERGY SYSTEMS, INC.

T N Tucker

T. N. Tucker
Engineer, Member ASME

Enclosure

METHANOL ECONOMY FOR THE PACIFIC NORTHWEST

(A discussion of how the construction of a methanol-coal slurry pipeline could affect the region.)

By: T. N. Tucker

This is a speech that was presented to a research committee meeting of the Oregon Voice of Energy on May 19, 1980.

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Letter #49 (continued)

Everyone knows that the United States has more recoverable coal than Saudi-Arabia has oil. The problem that we as a society must solve is how can our economy be adapted to efficiently use coal and its products. The direct combustion of coal usually requires the use of expensive scrubbers to minimize the release of sulfur into the air. But the new fluidized bed combustion technique seems to offer the ability to cleanly burn coal with extremely low emissions.

But not everyone can have a fluidized bed combustion boiler in their home or business. The system must be used to produce a form of power that can be readily transported and used by society.

Electricity is an obvious way to get energy to the consumer with minimal environmental problems. However, it suffers from thermal inefficiency in that only about 20% of the thermal energy released from coal actually arrives at the point of consumption.[1] This is primarily due to the inefficient steam cycle that must be used to power our turbine generators that are only about 35% efficient at generating electricity. More advanced combined cycle power plants should be able to raise this up to 60% but that still leaves 40% to be uselessly released to the environment.

The production of coal liquids from synfuel plants will be hampered because cancer causing compounds are also formed in the process.

Coal gassification offers perhaps the best answer to the environmentalist because the gases can be processed and filtered to remove any carcinogenic compound that may be formed, and because the products can be readily utilized by our society. Like natural gas, synthetic natural gas (SNG) can be efficiently transported to its destination where it can be used as an efficient source of heat. But SNG can't be used in vehicles without the use of high pressure fuel tanks with only fair combustion efficiency. Furthermore, SNG can't be used to displace the liquid hydrocarbon fuels that our society has become accustomed to burning in our vehicles, furnaces and boilers. Coal gassification requires far more water per ton of coal processed than gas coal liquification and coal transport via pipeline. So coal gassification alone is not the answer.

There is one clean burning liquid fuel that is capable of displacing gasoline and diesel fuels. It can be readily produced from the gases of a coal gassification plant. That fuel is methyl alcohol or wood alcohol, which is also know as methanol. It is made from the partial oxidation of any organic substance such as coal or biomass:

$$O_2 + \text{Hydrocarbon} + \text{Heat} \longrightarrow CO + H_2$$

$$C + H_2O \xrightarrow{\text{Steam}} CO + H_2$$

$$CO + 2H_2 \xrightarrow{\text{Catalyst}} CH_3OH$$

Although its heat value per gallon is about half that of gasoline, it has several redeeming characteristics that I feel make it superior to gasoline and diesel fuel.

Methanol can be used:

a) As a clean burning automotive fuel

b) As an economical source of hydrogen for use in fuel cells to produce electricity

c) As a chemical feedstock for a variety of industrial processes.

I will discuss these in more detail later.

Most methanol is currently produced from natural gas which could be used directly by industrial and residential consumers. If we can switch over to coal instead of natural gas, we will not only slow the exhaustion of a high quality fuel but we will also be converting coal into a readily useable form of energy that has essentially no environmental restrictions. If methanol is used in place of water to transport coal from the mine, then the already low water consumption of a slurry pipeline can be cut in half. It takes about one ton of water or methanol to transport one ton of coal. But it only takes about ½ ton of water to make one ton of methanol.[2] So methanol coal slurry pipelines permit the frugal utilization of the region's water resources, thus permitting the maximum production rate of coal.

Methanol appears to have a promising future because it can displace imported oil, reduce the fuel consumption of vehicles and improve the air quality in cities as

fringe benefits.

I would now like to share with you some observations that I have made on developments in related fields.

<u>Observations</u>

1. We have one coal fired plant located at Boardman, Oregon, with room available for two more. Each plant could burn 2.5 million tons of coal per year. This plant currently designed to consume 1.2 million tons at 40% capacity.

2. The Port of Portland is seriously exploring the feasibility of exporting 30 million tons of coal per year to Taiwan, Japan and Korea which have a total projected market of 100 million tons per year.[3]

3. Rail cars for coal transport are in short supply and that there is doubt that the railroads intend to meet the future demand.

4. Two-thirds of the price of exported coal is due to transportation costs.[4]

5. Coal slurry pieplines are the cheapest form of transportation available, with two technical limitations discussed below.

6. Lower export prices for coal will help America export more energy, thus improving our balance of payments and providing jobs for this region.

7. The amount of coal that can be exported or processed by synfuel plants is limited by the availability of water. The attached graph from the ASME journal shows that coal gassification requires the most water per ton of coal whereas water slurry pipelines require the least.[14,15]

8. One technique for partially refining coal involves the use of a high pressure methanol coal slurry pipelins where the methanol provides hydrogen to liquify perhaps 20% of the coal.[5] A portion of the coal would be converted to methanol at the mine's mouth and then used to transport and partially refine the coal during its journey. As a fringe benefit, the BTU content of the coal may be significantly increased due to the tendency for methanol to absorb water from the coal, thus reducing export shipping costs per million BTU's and improving combustion efficiency.

9. A centrifuge can readily separate the coal from the liquid mixture of methanol, liquid hydrocarbons, water and coal dust which can then be refined by simple distillation.

10. A methanol coal pipeline would consume only 50% as much water as a water-coal slurry pipeline, thus minimizing water consumption and maximizing the potential rate of coal production from water source regions.[2]

11. A natural place for a pipeline to terminate is Boardman, Oregon, because:
    a) Coal could be loaded directly into seagoing barges for direct export.
    b) Synfuel plants could use plentiful Columbia River water for coal processing.
    c) A natural gas pipeline already in place along the Columbia could carry synthetic natural gas from a gassification plant.[13]
    d) Methanol could be barged or piped to fuel terminals to Pasco, Portland, and Longview.
    e) The region is remotely located from population centers.

12. Methanol has the potential for becoming a substitute for gasoline and diesel fuel:
    a) Its low BTU rating is compensated by its naturally high octane rating of about 120, thus permitting the use of specially built high compression engines that are lighter than today's comparable gasoline engines.
    b) Air pollution emissions are extremely low. If methanol was available in sufficient quantity, a city could meet its air quality requirements for CO and HC by encouraging the sale of methanol in place of gasoline and diesel. Vehicle conversion would naturally be required. We already have 30 vehicles in Portland running on 100% methanol with no significant problems.[12]
    c) A recent study[6] showed that a small steam reformer can be used to convert a mixuture or methanol and water into hydrogen and CO_2 for on-board use in a fuel cell. This would overcome the storage problem that "hydrogen economy" advocates have not yet been able to solve.
    d) The 1986 projected cost for fuel cells is in the neighborhood of $200 per kw which is low enough to be competitive with combustion turbines.[10,6] Fuel cells will soon become practical power sources for stationary and mobile uses.[7,8]
    e) The future limiting factor for the technically forseeable "Methanol Economy" is supply and cost of the fuel.
    f) The largest industrial consumers of electricity use direct current (DC) rather than alternating current (AC) which is generated by power plants. Local fuel cells would generate DC power naturally without any conversion or rectification being required. Aluminum reduction plants are the best candidates for this because their contracts for cheap hydro-power are expiring and they need a source of relatively inexpensive and reliable power.

Letter #49 (continued)

Methanol powered fuel cells could also be used by utilities for peak loading, thus reducing the need for large thermal power. 17,18

13. Methanol is a versatile chemical feedstock that can be used to produce a variety of useful chemicals. The availability of commercial quantities of methanol would encourage the development of chemical synthetics industries throughout Oregon and Washington because a pipeline already links Seattle with Eugene. A methanol pipeline down the Columbia Gorge from Boardman could be easily tied with this distribution system.

14. Methanol fuel cell propulsion could be readily adopted by the railroads that currently use diesel generators to power their electric engines. The methanol fuel cells would be used in place of the diesel generators.

15. A longrange use of methanol in Portland would be for the production of liquid hydrogen (LH_2) at Portland's International Airport. Lockheed's LH_2 tranaports are already in the final design stages and the availability of LH_2 will play a significant role in determining which airports will be serviced by these aircraft. Since Portland's airport is adjacent to the Columbia River where the proposed methanol pipeline could be laid, it would be relatively simple to construct an LH_2 facility adjacent to the airport, thus avoiding the construction of coal gassification plants for the production of LH_2 adjacent to the airport as is planned elsewhere.

16. Last but not least, the mass production of methanol will one day permit the one stop delivery of energy to homeowners and buainesses that could use methanol as follows:

   a) To displace diesel heating oil in boilers and furnaces. Later new catalytic heaters will be available that will be 100% efficient because their emissions will be so low they won't require venting of their combustion gases. We already have such heaters that have been approved by UL for the combustion of light kerosine.

   b) To fuel internal combustion engines in vehicles, thus bypassing the traditional gas station. It will also be available to fuel the future methanol-fuel cell electric vehicles when they become available.

   Note: The intermediate use of methanol is seen as a vital step toward the practical methanol fuel cell vehicle because manufacturers won't mass produce an advanced vehicle if only limited amounts of fuel are available.

   c) The DC power from a bank of $200/kw fuel cells will go hand-in-hand with the daytime solar DC power that will be available from the projected $200 to $500/peak kw. solar cells that will be available at about the same period of time.[10] Both power sources will require a converter to tie into the local utilities' AC power lines. The fuel cells could

operate during cloudy weather and when the sun is down at night, thus minimizing the load fluctuations that the utility will have to contend with. Some remote installations will be able to supply all of their own electricity this way. Since methanol can be burned directly to provide heat for cooking and space heating, the peak electrical load will be reduced to the relatively small load required by fluorescent lighting, microwave oven, and small motors for the refrigerator, air conditioner and freezer.

I hope that you don't think that the Methanol Economy that I have described above is too impractical to be seriously considered at this time. Virtually all of the technology has already been demonstrated and will be available within the next ten years. But they won't be implemented without a coordinated development plan that will provide for the following:

1. Large volumes of methanol at a price that is competetive with diesel and gasoline.
2. Medium to large scale transportation demonstration projects where fuel cells are used to propel buses, trucks and trains.
3. The encouragement of methanol production from coal (and biomass) for use in methanol-coal slurry pipelines.
4. Government purchase of engines that are designed to get optimum performance from 100% methanol fuel.
5. Government purchase of small methanol-fuel cell power aupplies to replace diesel and gasoline powered generators. This should be coordinated with the use of solar panels with fuel cells being used as backup and power boosting when required.
6. Funding of studies on the economics of methanol coal pipelines for various regions of the United States.
7. Fund a demonstration project conversion of an aluminum plant over to a methanol fuel cell power supply.

Coal can play a vital role in developing alternatives to our current OPEC diet of oil. One day our society may look back on the 1973 oil embargo as a blessing in disguise because it prompted us to develop our own resources.

For those of you who are nuclear power advocates, I would like to recommend that you expand your horizon beyond simply producing electricity. The high temperature liquid metal or helium cooled reactor of the forseeable future can be used to produce much more than steam to power a turbine generator. Here are just a few of the possibilitiea:

1. Water can be dissociated directly into oxygen and hydrogen which then can be used:
   a) to power fuel cells directly,
   b) to produce hydrogen for synthesis of methanol by combination with CO_2 derived from a liquid air facility.
   c) to produce ammonia by combining hydrogen with nitrogen from a liquid air facility. Fertilizer manufacturera now obtain hydrogen from natural gas.
   d) to cool a super conducting DC power line that could transmit both power and LH_2 to major load centers. The LO_2 could be boiled off to keep the outer shell of the powerline cool. This approach would reduce energy losses that are found with conventional power lines.

By integrating a high temperature power plant with an air liquification plant, ammonia plant, methanol synthesis plant and oxygen-hydrogen fuel cell power generator, we can abandon the thermally inefficient steam cycle and efficiently consume almost all of the generated heat. Cooling towers would no longer be necessary. The buildup of atmospheric CO_2 could be alowed because for the first time mankind would be abandoning the solar plant cycle and extracting CO_2 from the air for direct production into fuel.

In conclusion, I would like to say that methanol is a fuel that deserves far more attention than it has been receiving to date. I think that it is time for public discussion of the above ideas. After all, the public will ultimately have to pay for and live with whatever synthetic fuel program that is ultimately developed. The public has already let us know what it thinks about the current status of nuclear power, and they have done so with resounding impact.

I think that it is time that we came up with a future energy program that can be readily embraced by the public. Such a program must carefully meet the needs of industry for large amounts of electricity as well as the individual who may want the option to be totally independent of the oil companies and utilities. It must also consider this country's vast resources of coal and the vast amounts of wealth and capitol that leaves this country every year we continue to import energy. It must also consider the sincere environmentalists' wish that this country will be a safe and beautiful place for his children and grandchildren. It must also balance this with the fact that the quality of life of every American depends upon the consumption of energy. When energy is too expensive or unavailable for efficient utilization by consumers and industry, then our quality of life is hurt. We have seen this in the form of aluminum pot lines being shut down for lack of affordable electricity, and we have seen gas lines and the spectre of gas and oil rationing looming on our political horizon today. Those who do not agree that the quality of life and the efficient utilization of abundant energy go hand in hand should step aside and allow us to proceed provided reasonable environmental safeguards are taken.

Let's kick these ideas around for awhile. I would like to know what you and your friends have to say about the methanol economy. Only by working together can we take the helm of our future energy policy.

Letter #49 (continued)

BIBLIOGRAPHY

This bibliography was compiled on May 28, 1980, to provide documentation and technical details to facilitate review and comment by interested parties.

The author welcomes any questions that may arise: telephone, (503) 226-3303 days; (503) 282-1536, evenings.

Footnotes

1) "The Role of Natural Gas in Supplying the Energy Needs of Oregon," Northwest Natural Gas Company, a report to Victor Atiyen, Governor of the State of Oregon. (no date) p. 19.

2) This is a rough approximation because the actual water consumption depends upon the process used to produce carbon monoxide and hydrogen from the coal.

$$CO + 2H_2 \longrightarrow CH_3OH$$

Usually the oxygen is obtained from reacting coal with H_2O:

$$\underset{12\ lb}{C} + \underset{18\ lb}{H_2O\ (steam)} \longrightarrow \underset{28\ lb}{CO} + \underset{2\ lb}{H_2}$$

In this equation, 12 lbs. of carbon reacts with 18 lbs. of water to form the precussors of methanol carbon monoxide and hydrogen. Since coal can contain from 2.8% to 22% water as Wyoming's sub-bituminous coal does, a significant amount of water need not come from a separate source. If commercial oxygen is available from the air via filtration or cryogenic separation, then even less water will be consumed.

3) Telecon between the Port of Portland's Mr. L. D'Amico and Tom Tucker on April 24, 1980.

4) Conversation with Ms. L. Layman of NERCO on May 2, 1980.

5) This is the donner solvent technique where a light hydrocarbon liquid is used to chemically donate hydrogen to the large coal molecules which then liquify after a hydrogen atom is attached to their broken hydrogen chain bands.

Lacey, J. J., "Overview of Coal Liquification in the U.S. Department of Energy," ASME 79-PVP-45, p. 4.

Stewart, J. T. and Kelett, M.G., "Coal Conversion for Feedstock and Fuel," ASME 78-PET-17, p. 5.

6) "Fuel Cells for Transportation," by J. Byron McCormick of Los Alamos Scientific Laboratory, Industrial R&D, April 1980, pp. 88-92.

7) "Utilities Finally Put Big Money on the Fuel Cells," "Business Week", April 21, 1980, pp. 70, 71.

8) "Power Plant Operation" (Using fuel cells), Industrial R&D, April 1980, p. 33.

9) Ibid. ref. 6, p. 92.

10) Backus, C. E., "Photovoltaic Power Systems: An Overview", Mechanical Engineering, April 1980, p. 44.

Table I reports goals of $500 per peak watt by 1986 and $100 to $300 by 1990-2000 using 1975 dollars.

11) Campbell, T. C., "Coming: New Coal Transportation Modes," Mechanical Engineering, September 1979, p. 39.

12) Personal conversation with Gary Griffith of Griffith Auto in Portland, Oregon, on May 2, 1980.

Vehicle	Oregon State Limits	Actual
1975 Chevrolet ½ ton pickup 454 in^3	2% CO 300 PPM HC	½% CO 60-80 PPM
1977 Dart 6 Cylinder	.5 CO 125 PPM HC	Below Detectable Limits

Note - The Griffith's conversion requires the removal of pollution control equipment which is being opposed by the DEQ which, according to Bill Jasper of the Portland DEQ, made it unsuitable for testing.

Methyl alcohol must also be officially recognized as an automotive fuel when used 100% and not merely used as a blend to boost octane.

13) The author notes that on May 20, 1980, Northwest Pipeline Corp. proposed the construction of a coal slurry pipeline from Wyoming to Oregon to supply coal for the production of pipeline quality gas, electric power and export to the Far East. A Department of Energy grant is being requested to study this proposal.

The author recommends that the scope of this study be expanded to include the use of methanol as described herein.

Methanol in place of gasoline - The author does not see any reason why methanol could not be satisfactorily substituted when specially designed engines are used. Although methanol has a relatively low heat value per gallon (56,560 BTU/Gal vs. 115,400 BTU/Gal for gasoline). This must be weighed against its naturally high octane rating of 116 which permits the use of high compression engines (12:1 compression ratio), thus permitting the extraction of more work per unit of heat input.

14) Naso, E. J., "Coal Slurry Pipeline for the Next Decade," "Mechanical Engineering", December 1979, p. 41.

15) English, J. T., "Improved Coal Slurry Pipeline," NASA Contract #NAS 7-100, Vol. 4, No. 1, Item 35, from JPL Invention Report 30-3822/NPO-14425.

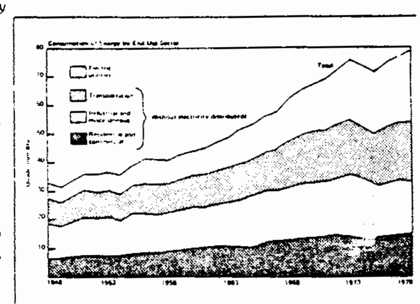
SPECIAL REPORT FUEL CELLS

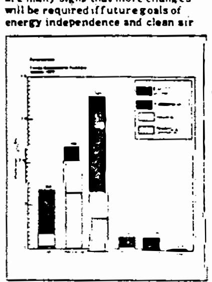
Fuel Cells for Transportation

J. Byron McCormick
Los Alamos Scientific Laboratory

IN THE LATE 1960s, the air pollution generated by automobiles became a vital nationwide issue. In 1973 the oil embargo demonstrated America's vulnerability to foreign pressure, primarily because of her dependence on automobiles powered by gasoline-burning internal combustion (IC) engines. In 1979 transportation needs accounted for approximately 25% of the total U.S. energy consumption, and approximately 50% of the petroleum usage.

In response to economy-environment pressures, the auto industry has responded with smaller, lighter cars, lean-burn engines, catalytic converters, and more diesel engines. However, there are many signs that more changes will be required if future goals of energy independence and clean air are to be achieved.





Energy consumption charts on this page from February 1979 Dept. of Energy report "Application Scenario for Fuel Cells in Transportation."

In particular, future automotive propulsion systems should exploit nonpetroleum energy resources and use those resources as efficiently as possible. One promising approach is the fuel cell.

The fuel cell converts chemical energy directly to electric energy. The most common types of fuel cells are hydrogen-air cells, which generate electricity directly from the chemical reaction of hydrogen + oxygen → water.

The most important property of a fuel cell is that the energy conversion efficiency is not limited by the Carnot cycle as are heat engines. Theoretical efficiencies for a pure hydrogen fuel cell could be as high as 83%. Fuel cell systems with efficiencies greater than 50% already have been fabricated.

Fuel cells have been used extensively in space applications. More recently, fuel cell development has been geared toward utilities' applications. As a result of these efforts, fuel cell performance has been greatly improved.

In particular, the weight and size of the fuel cell has been reduced to levels reasonable for vehicular application. Furthermore, the price of fuel cells is predicted to drop dramatically in the next few years. Price reduction due to basic design improvements, combined with mass production techniques, could make the fuel cell economically competitive with IC engine in the foreseeable future.

Most importantly, because the fuel cell inherently has such high energy efficiency, substantial energy savings could result from the conversion to fuel-cell-powered automobiles. This fact alone mandates that the fuel-cell-powered vehicle be given careful consideration as a possible replacement for the internal-combustion-engine automobile.

Based on these considerations, in August 1977 a fuel-cell-powered vehicle workshop was held at the Los Alamos Scientific Laboratory (LASL). Representatives from the fuel cell industry, automotive industry, national laboratories, and universities met to consider the application of fuel cells to vehicular transportation.

The primary vehicle considered was the fuel cell/battery hybrid vehicle, in which the fuel cells are paralleled by batteries. In this configuration, the fuel cell is sized to provide power for steady-state 55-mph cruising. The battery is sized for acceleration and for providing power to the vehicle during fuel cell warmup.

Regarding the question of fuel cell type to be applied to vehicles, the workshop participants concluded that, for the near term, the fuel cell of choice, based on the development of fuel cells for the utility applications, should be the phosphoric acid electrolyte cell. Cells with other electrolytes might provide significant advantages, but they will also require additional development.

With regard to fuels, any source of hydrogen (coal, nuclear, solar, or biomass) could be used. It should be noted that the fuel cell vehicle is currently compatible with the "hydrogen economy."

The workshop attendees also concluded that the near term fuel of choice should be a coal-derived liquid, of which methanol (methyl alcohol) is the leading candidate. The methanol would be steam reformed on board the vehicle to provide hydrogen. In steam reforming, the fuel, mixed with water, is passed over a hot catalyst bed to yield hydrogen and CO_2. Waste heat from the fuel cell may be used to heat the reformer and increase the system energy efficiency.

As with phosphoric acid fuel cells, the state of the art of reformers was felt to be well developed. Although it was agreed at the workshop that the fuel-cell-powered vehicle does indeed hold great promise, it was also concluded that a more-detailed evaluation should be undertaken.

Following the recommendations made at the workshop, various vehicular applications for fuel cells were evaluated in a joint program between Brookhaven National Lab, U.S. Army MERADCOM, and Los Alamos Scientific Lab.

As recommended, the phosphoric acid fuel cell was used as a baseline for these evaluations. Data on representative fuel cell systems, using current technology, were derived by Energy Research Corp. (ERC).

Two cell sizes (15 and 60 kW) and two fuel options (methanol and propane) were included. Four vehicle types, city bus, highway bus, delivery van, and general-purpose consumer car, were selected for evaluation. Typical drive cycles and economics for these vehicles were gathered, and comparisons were made between the fuel cell vehicle and current internal combustion engine vehicles.

The conclusions of these evaluations are briefly related in the following four subsections. Since the price of petroleum-based fuels has increased dramatically since this work was concluded (in fact surpassing our 1990s estimates), the statements regarding fuel costs and savings have been generalized to indicate approximate levels rather than exact dollar amounts.

City Bus. In considering possible fuel-cell-powered vehicle applications, the city bus is found to have a number of attractive features. The procurement cost of a city bus is 80% subsidized by the Federal Government. Therefore, the increased costs in using a high-priced fuel cell (pre-mass production) are less important to the user.

In total dollar outlay, the cost of fuel and maintenance for buses tends to dominate the procurement costs. Also, because of particulate pollution and exhaust smells usually associated with city buses, pollution is a serious consideration. [illegible] specifications were based on [illegible] performance of a current diesel-powered 25,000-lb, 40-ft bus.

Because of the diverse and often inconsistent nature of the drive cycle data available, the report contains a number of "apples and oranges" comparisons, which were "worst-cased" whenever possible. In general, the results derived suggest the potential technical and economic feasibility of a fuel-cell-powered city bus.

The battery of choice for the hybrid configuration was the nickel-zinc, due to the limited charge rate of a lead-acid cell.

Generally, the city bus is perceived as a good application for fuel cells. This application represents a market of 5,000 vehicles per year (at a cost in excess of $100,000 each), which would increase the manufacture of fuel cells in a reasonable increment without demanding ultimate mass production costs.

Several fuels were considered. Propane is the most practical in the near term. Diesel fuel was ruled out because of its high sulfur content. It also was pointed out that in the future, as petroleum costs increase, methanol should become an important alternative.

Using the ERC data for a 60-kW phosphoric acid fuel cell, a modest weight decrease was noted and volumetric feasibility was demonstrated.

Fuel cost savings were also projected for the future using methanol. Moreover, the costs of fuel, maintenance, and bus procurement were found to be small when compared with the total costs of running a bus line. From this point of view, it was speculated that the future motivations for a fuel-cell-powered bus might well be based on fuel availability.

Furthermore, the visibility of the application is seen as a long-term benefit in demonstrating the value of fuel cells and fuel-cell-powered vehicles.

Highway Bus. Technically, the highway bus appears to be an excellent application for fuel cells. The available volume is more than adequate to accommodate a fuel cell/reformer system and the relative weight increase caused by such a system is small.

Vehicle procurement costs would be increased about 17%. At current fuel costs, a propane-powered fuel-cell bus would cost approximately the same to fuel as a diesel bus. In the future, the fuel-cell bus running on methanol was projected to save several cents/mile in fuel costs.

The fuel economy in 1990 over a million-mile bus lifetime could offset tens of thousands of dollars of the procurement differential. These savings, when combined with reduced maintenance costs, could save substantial sums over the vehicle life.

These results, independent of the long lifetime potential, suggest that the fuel-cell-powered bus and large highway truck could be an economically and technically viable option for the 1990s.

Consumer Vehicle. A theoretical fuel-cell-powered consumer car was evaluated. A Volkswagen Rabbit was used as a base line vehicle for comparison purposes between the gasoline engine, diesel engine, and fuel cell. A 15-kW fuel cell version provided performance comparable to that of the diesel Rabbit. Four kilowatt hours of lead acid battery were used for cold start at F. (Conservatively, it was assumed that the vehicle would be able to cruise at 55 mph on the battery power only for the entire 10 min required for fuel cell start up.)

The weight of the vehicle was increased by 251 kg; 127 of the extra kilograms are attributable to the batteries.

Using cost and vehicle mark-up data derived from several sources, including Ford Motor Co., DOT, and Volkswagen, and assuming $200/kW for the fuel cell reformer system, a fuel-cell-powered Rabbit was projected to have a price of $7,240.

Fuel consumption was calculated for the [illegible] course and the J227 metropolitan drive cycle. Substantial improvements in vehicle system efficiencies were [illegible] and the escalation in gasoline prices suggests a substantial payback base for fuel savings. It was projected that reduced maintenance costs and reliability could also be favorable factors in the marketplace.

Throughout this analysis, the question of consumer buying preferences was addressed. It was observed that simple utility does not appear to be the dominant factor in consumer preferences. As a result, it was felt that the low noise, low pollution, and reliability of the fuel cell electric car could play important roles in consumer acceptance.

This evaluation produced surprisingly positive results. It did not show that fuel cells were immediate replacements for the internal combustion gasoline and diesel engines, but it did demonstrate that a fuel-cell-powered consumer car could be a viable option in the future.

Delivery Van. A conventional battery electric vehicle with fuel cell augmentation for on-board recharging was found to be the most promising configuration for a delivery van. Unfortunately, data on delivery van drive cycles are difficult to obtain; therefore, no detailed analysis or preliminary system design was performed.

It was concluded, however, that a fuel cell van of this type deserved should be significantly more efficient than a comparable internal-combustion-engine-powered vehicle. This is because the gasoline and diesel engines are most inefficient in the start-stop, largely idle delivery regime.

The fuel cell electric configuration would also increase the range and number of possible applications for electric delivery vans. Reduced maintenance was suggested as an economic incentive for the development of the vehicle.

Maintenance cost reductions (30 to 50%) for battery-powered electric vans already have been demonstrated by several electric vehicle fleet users. Further reductions in maintenance are expected with the addition of the fuel cell, as batteries represent a majority of the maintenance costs in conventional electric vans. The fuel cell not only reduces the number of batteries, but also maintains a voltage across the cells, thus prohibiting deep discharge (increasing lifetime).

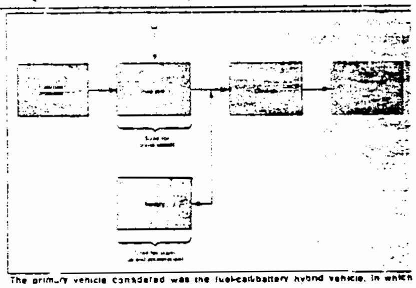
It should be noted that the conclusions drawn for the fuel-cell-enhanced delivery van concept might well be extended to a fuel-cell-enhanced commuter car.

Economic Conclusions. The results of the economic analysis of the four target vehicles strongly suggest the feasibility of the fuel cell vehicle in the future. It should be emphasized that no fuel cell, battery, motor, or vehicle aerodynamic performance improvements were projected in making these assessments.

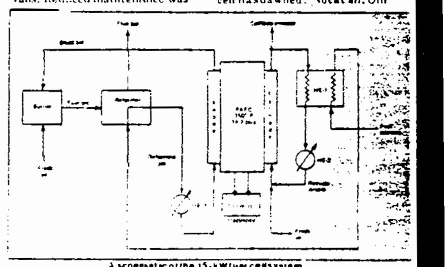
Technical feasibility was demonstrated in each of the four vehicles studied. Economic viability was more difficult to prove because of the scarcity of uniform vehicular performance, duty cycle, and economic data, and the lack of experience with fuel cells in the vehicular environment. However, since conservative rather than optimistic estimates were used in the analysis, first-order economic viability was predicted.

Is it fair to say, based on the results of these studies, that the internal-combustion-engine car is finished and that the age of the fuel cell has dawned? Not at all. Our results to date do demonstrate that the fuel-cell-powered vehicle has potential. With today's technology, acceptable performance levels can be achieved; but careful and systematic development of both fuel cell systems and the associated vehicular system will be required.

However, it should be equally emphasized that the advantages of such a vehicle are large. The potential for the efficient utilization of nonpetroleum fuel in an environmentally considerate manner suggests strongly that the fuel cell should be given serious consideration as an alternative for the future. ☐



The primary vehicle considered was the fuel-cell/battery hybrid vehicle, in which the fuel cells are paralleled by batteries.



A schematic of the 15-kW fuel cell system.

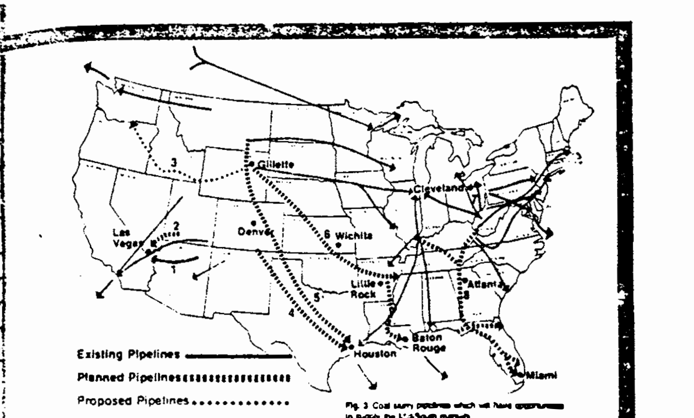


Fig. 3 Coal slurry pipelines which will have opportunities to supply the U.S. South markets

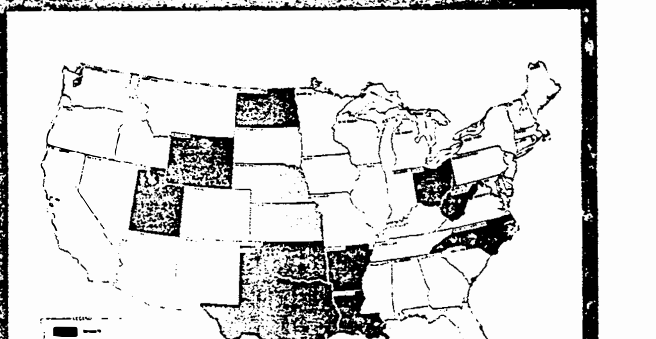


Fig. 4 States having eminent domain for coal slurry pipelines

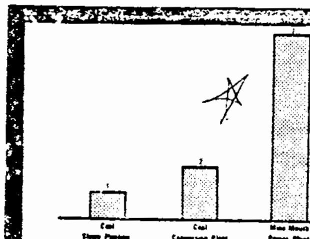


Fig. 5 Relative water consumption

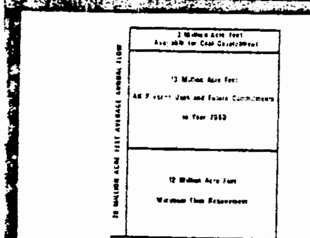


Fig. 6 Water available from the Missouri River at Sioux City

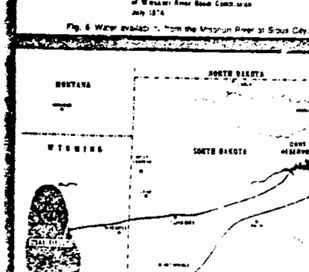


Fig. 7 How surface water for Powder River Basin coal development can be piped from the Oahe Reservoir

cross such public lands must be obtained from federal and state agencies. Easements will also be required for privately owned parcels. Most of these permits and easements are routinely acquired and pose few problems to the construction of a pipeline.

The major obstacle is the railroads, which historically have refused crossing permits to competitors. For example, in 1875, Columbia Conduit System, operator of a 3-in. (75-mm) 60-mi-long (100-km) crude oil pipeline, had to use tank wagons to move crude across the tracks. In 1942, the Cole Act was passed by Congress, granting wartime petroleum pipelines the temporary right of eminent domain because of the opposition of the railroads. Granting rights-of-way for coal slurry pipelines has met with particularly vehement opposition from the railroads because to date the railroads have had a virtual monopoly on the movement of coal. The railways have mounted a large, well-funded program of opposition and are quite frank in stating their desire to forestall competition.

Without rail crossing permits, there are three alternative methods of obtaining permission to lay a pipeline across the tracks: federal eminent domain legislation, state eminent domain legislation, and private acquisition.

Federal Legislation. Federal legislation granting the right of eminent domain to coal slurry pipelines was first introduced in 1962 by President Kennedy. The bill, which would have triggered the building of a coal slurry pipeline from West Virginia to New York and New Jersey, was defeated due to the opposition of the powerful eastern railroads. A fallout of this eminent domain effort was the banding together of five railroads to effect a massive rate reduction out of District 8 in Ohio on the condition that the Ohio Coal Pipeline cease operation. The rate reduction was obviously not in their immediate economic interest because the pipeline was moving only a little more than 1 million tons (0.9 million t) of the total 5 million tons (4.5 million t) of coal moved out of District 8 each year.

In 1974, as a result of the Arab oil embargo and the need for the U.S. to develop its most abundant and cheapest energy resource, coal slurry pipeline legislation was again introduced in both the Senate and the House. The Senate bill moved quickly through committee and passed on the floor by voice vote. It was then referred to the House Interior Committee, where successful lobbying by the railroads obscured the real issue and caused it to die.

In 1975, similar legislation was introduced in the House and lengthy hearings were held throughout the year. Again, the powerful opposition of the railroads resulted in a measure requiring the undertaking of a study to gather information. The legislation was subsequently tabled in committee by a vote of 21 to 19 in June 1976, to await the results of the study.

The Coal Pipeline Act of 1977 was introduced in January 1977, and after passing out of several committees, it reached the floor of the House for vote in July 1978. Although intensive railroad opposition was successful in defeating the bill on the floor, progress was made over prior years in that at least the bill was brought to a vote. As the energy crisis deepens and the broad support for coal slurry pipelines grows, the pro-

Letter #49 (continued)

FUEL CELLS

Power plant operation

FUEL CELL POWER PLANTS convert the energy of a fuel directly to electricity by an electrochemical process. Their efficiency isn't limited by the Carnot-cycle principle of thermal machines. Because the same electrochemical reactions occur in each individual cell, power plant efficiency is nearly independent of the number of cells and plant size. Fuel cells thus have several attributes not found in thermal power generators:

[illegible] efficiency. A level of 38% is projected for initial units, with a potential for over 50% in the future. Fuel cell efficiencies are essentially constant over a wide range of loads and down to a capacity of 10 MW or less.

Environmental compatibility. NO_x, SO_x, and particulate emission levels are lower than any projected requirements. Fuel cell plants are also water-conservative and quiet.

Modular design. Because fuel cells will be factory-produced with short lead times, and because performance is virtually independent of plant scale, they can be used to increase utility system capacity by small increments in response to demand growth. Capital liability is thereby minimized.

Versatility. Fuel-processing and power-conditioning options provide flexibility in both the type of fuel used and the power introduced into the bus. For example, the power conditioner can be used to control real and reactive power independently.

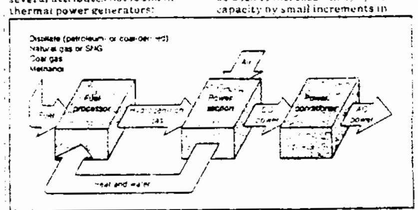
Because of their efficiency, environmental compatibility, and modular character, fuel cell power plants are most attractive for the utility industry in two roles:

Dispersed peaking or load following. Sized and sited as required, even in environmentally constrained urban and suburban zones, they would:

- Enable deferral of T&D investment
- Allow other generators to operate at maximum efficiency
- Permit rapid, low-cost capacity expansion
- Conserve premium liquid and gaseous fuels

Dispersed dual energy use. Fitted with equipment for recovery of reject heat, they would:

- Use fuel at an overall efficiency approaching 80%
- Allow a utility to adopt fuel cells primarily for economic electricity dispatch and at the same time gain a substantial credit by siting them near heat users
- Help utilities cooperate actively with national energy policy and the current emphasis on cogeneration



A fuel cell plant consists of three major subsystems. The fuel processor (reformer) converts a conventional, available utility fuel to a hydrogen-rich gas. The power section (composed of fuel cell stacks) converts hydrogen and oxygen (from ambient air) to water and electricity. The power conditioner converts dc power to ac power compatible with the utility bus.

Dispersed power plants are not likely to use coal or other environmentally difficult fuels directly. Fuel cells for peaking or load-following service will use any of several liquid or gaseous fuels derived from petroleum or coal.

Other first-generation fuel cells, with minor design modifications, will be able to use coal gas, SNG, methyl fuel, or coal-derived distillates that meet similar sulfur-content and boiling-point criteria.

Future dispersed fuel cells will be designed to use any of these fuels and also distillates having a sulfur content of up to 2,500 ppm and an end boiling point below 313 C.

Power plant heat rates will vary somewhat because fuel-processing requirements depend on the fuel used. In all cases part-load heat rates will be less than full-load values, making fuel cells attractive load followers.

The major advantages of fuel cells derive from their environmental compatibility and ready siting and from their efficiency and economy across a wide range of loads and unit sizes. Beyond this, they offer distinct advantages also for electricity dispatch in utility system operations. While these advantages are specific to individual systems,

Fuel Cell Market Potential in the Year 2000

Heat Rate (Btu/kWh)	Capital Cost* ($/kW)	Market Penetration (%)
Large utilities		
9300	350	4–27
[illegible]000	320	30
7500	475	38
[illegible]500	[illegible]50	40*
Small utilities		
[illegible]	[illegible]	[illegible]–40*
[illegible]	[illegible]	[illegible]–40*
[illegible]	[illegible]	40*

[illegible]

Fuels and Heat Rates (Btu/kWh)

Fuel	Full Load	Half Load
Distillate	[illegible]	[illegible]
Natural gas	[illegible]	[illegible]
SNG	[illegible]	[illegible]
Coal gas	[illegible]	[illegible]
Methyl fuel	[illegible]	[illegible]
Hydrogen	[illegible]	[illegible]

INDUSTRIAL RESEARCH & DEVELOPMENT—APRIL 1980 2

Letter #50

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
Environmental & Technical Services Division
P.O. Box 4332, Portland, OR 97208

June 12, 1980

F/NWR5:SHS

Mr. Sterling Munro, Administrator
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

Dear Mr. Munro:

The National Marine Fisheries Service has reviewed the revised draft environmental impact statement for The Role of the Bonneville Power Administration In the Pacific Northwest Power Supply System.

In order to provide as timely a response to your request for comments as possible, we are submitting the enclosed comments to you directly, in parallel with their transmittal to the Department of Commerce for incorporation in the Departmental response. These comments represent the views of the National Marine Fisheries Service. The formal, consolidated views of the Department should reach you shortly.

Sincerely yours,

Dale R. Evans

Dale R. Evans
Division Chief

Enclosure

Letter #50 (continued)

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
Environmental & Technical Services Division
P. O. Box 4332, Portland, Oregon 97208

June 12, 1980 F/NWR5:SHS

TO : PP/EC - Joyce M. Wood

FROM : F/NWR5 - Dale R. Evans

SUBJECT: Comments on Revised Draft Environmental Impact Statement -- The Role of the Bonneville Power Administration In the Pacific Northwest Power Supply System (DOE, BPA) DEIS #8004.05

The draft environmental impact statement for The Role of the Bonneville Power Administration In the Pacific Northwest Power Supply System that accompanied your memorandum of April 7, 1980, has been received by the National Marine Fisheries Service for review and comment.

The statement has been reviewed and the following comments are offered for your consideration.

General Comments:

The National Marine Fisheries Service (NMFS) is providing its comments on the revised DEIS based on its legal jurisdiction and expertise with regard to living marine resources under the National Environmental Policy Act (NEPA), the Fish and Wildlife Coordination Act (FWCA), the Anadromous Fish Conservation Act, and other authorities. In particular, NMFS' comments on the DEIS reflect its responsibility and concern for the protection, mitigation, and enhancement of anadromous fish stocks (salmon and steelhead) and their habitat.

Our reading of the draft EIS indicates that the alternatives presented represent a greater or lesser BPA role in the regional power system, and a greater or lesser implementation of the "one utility concept" for the Pacific Northwest. Under the Council of Environmental Quality (CEQ) guidelines, the analysis of alternatives is deemed to be the "heart" of the EIS (§1502.14); it must consider those alternatives in detail "so that reviewers may evaluate their comparative merits;" provide a basis for "defining the issues, and providing a clear basis for choice;" and include appropriate mitigation measures. 1

The alternatives analysis in the BPA Role DEIS falls short of these goals. The level of analysis presented is of such a general and vague nature that comment becomes difficult -- to comment effectively would require the writing of a substitute analysis. More precisely, there is little indication of the programs BPA would carry out under each alternative, e.g., the extent of load management and peaking modifications which BPA contemplates under each alternative. Without such detail, comparative merits and environmental impacts are difficult if not impossible to assess, and issues cannot be sufficiently defined to provide an informed basis for selection among the alternatives.

2

This inadequacy in the detail of alternative analyses necessarily transfers to the evaluation of environmental consequences. With respect to anadromous fish and their habitat, impacts of existing and future operations of the power system are discussed in only the most general terms and in a conclusory rather than an exploratory manner. The comparative impacts to fisheries in the range of alternatives simply cannot be assessed on this basis. Thus, it is difficult to see how the BPA Role DEIS satisfies §1502.16 of the CEQ guidelines, which require "an analytic basis" for environmental impact comparisons, including an assessment of direct and indirect effects. Other aspects of environmental analysis required by the CEQ guidelines [§1502.16(a) - (e)] are also unaddressed -- e.g., "possible conflicts between the proposed action and the objectives of Federal, regional, State, local...Indian depletable resource requirements" relative to anadromous fisheries; and mitigation measures available to protect anadromous fisheries.

As for the data used in the BPA Role DEIS, little documentation or scientific support is provided. With respect to anadromous fisheries this lack of documentation and quantitative analysis cannot be attributed to a corresponding lack of data. On the contrary there is much research data available on the impact of hydroelectric projects on these fish and their habitat, as well as mitigation measures which address or alleviate these impacts. NMFS would be able to provide an overview of this research upon request, in order to satisfy the CEQ guideline requirement that the scientific integrity of the EIS analyses be assured and documented (§1502.24). Where quantitative or other research data are not available, a "worst case" analysis should be used, with an indication of probability or improbability (§1502.22). In the case of anadromous fish, detrimental power operations and destruction of already limited habitat might well result in the extinction of historical runs. Indeed, this may have already occurred to certain upriver stocks, and most of the remaining upriver stocks show serious declines in population levels. 2

Finally, we believe that the DEIS as drafted discourages meaningful public and agency comment. Although the subject matter presented in the DEIS is extremely complex and esoteric, it appears that little attempt was made in the preparation of the DEIS to accommodate the lay audience. For example, there is no glossary, no explanation of concepts, agreements and organizations to assist the reader; there are referrals to other documents from which the basis of several assumptions and scenarios are formulated without explanation. These inadequacies can only intimidate the reader and result in superficial or incomplete review by affected interest groups and agencies. 3

Specific Comments:

Page I-6 to 9. The statement of BPA Mission and Goals and Guideline Principles should include recognition of the Administrator's obligation to give preservation and enhancement of fish and wildlife equal consideration with power purposes. This is mandated under the FWCA. 4

Page I-10. Generally, we support the "one utility concept," if the concept is interpreted so that the benefits and flexibility of operating as one utility inure to the benefit of fisheries production as well as power production. This has not been the case to date -- fisheries have not been adequately incorporated into planning and operational decisions on more than an ad hoc, short term basis. 5

Letter #50 (continued)

3

Page I-13 to 20. The discussion of "other Environmental Analyses" does not clarify the relationship of the DEIS to other EIS's which might be prepared, particularly since this DEIS does not actually represent a proposed "program." The statement should discuss whether BPA will prepare a more detailed programmatic EIS on the selection of its program, -- describing e.g., what conservation measures are proposed, including peakload management, the related fishery benefits, and impacts of various alternative measures which would comprise the BPA program. 6

The DEIS should state whether a new NEPA document would be prepared if the proposed northwest power bill becomes law. At least with respect to anadromous fisheries, which would have increased standing in power planning under the bill, it appears that a supplemental EIS would be required.

Page I-28, last paragraph. With respect to transmission line services and planning and the one-utility concept, BPA should use these authorities and approaches to encourage and smooth the implementation of fishery improvement measures. This is in keeping with the "equal consideration" requirements of the FWCA. 7

Page I-29, first paragraph. With respect to power planning, anadromous fishery requirements must also be considered as an underlying and "given" planning assumption. This is in keeping with the "equal consideration" requirements of the FWCA. 8

Page I-34. As noted in our General Comments, the "Ranking Alternative" does not actually represent a program. There is no clear indication of the actions BPA would propose to take under each of the areas identified to a degree necessary for accurate assessment and comparison of environmental impacts. All alternatives must include consideration of fishery impacts in both power planning and operation in view of the FWCA. 9

Page I-38. As noted in our General Comments, a "worst case" analysis of the impacts of hydroelectric dam operations on anadromous fish would reflect the ultimate extinction of certain upriver stocks. 10

Page II-4, section D. The residential and industrial use patterns noted here underscore the availability of load management alternatives and improved energy efficiency as a means of meeting demand. In turn, such measures could minimize adverse impacts to anadromous fisheries.

Page III-5, paragraph 2. We disagree with the characterization of the BPA role as "institutional." Certainly BPA has sizable influence in the substantive areas of energy direction for the Northwest as a whole, through its use of statutory authorities. How BPA uses its influence (and to what ends) affects environmental impacts to a great extent. This is clearly evident from a reading of northwest power bill proposals and further discussions in the DEIS. 11

Page III-8, paragraph B.1.b. The second paragraph on "Customer Services" indicates that they are conditioned on environmental restraints. The DEIS should discuss how and to what extent these services are conditioned, particularly with regard to fisheries. We are particularly concerned about how fishery-related restraints would be incorporated into load factoring and forced outage reserves (Page III-9). The "one-utility concept" should allow the incorporation of fishery concerns into these and other areas, with greater flexibility than is presently utilized. 12

4

Page III-13, paragraph d.(1). Fishery-related concerns should be reflected in all aspects of power planning. With respect to load forecasting, the data base used should include fish protection requirements. 13

Page III-14, paragraph d.(2). The second paragraph of "Power Planning Document" indicates the availability of some public involvement and input, and could be read to include fishery agency input to the extent "available and appropriate." We suggest that the DEIS describe public and fishery agency involvement more specifically here, and that this involvement be fully provided for at all critical stages of document preparation. 14

Page III-15, paragraph d.(4). Utilization of "current planning assumptions" will not satisfy BPA obligations under the Fish and Wildlife Coordination Act. Current planning assumptions must be revised to include "equal consideration" of fish and wildlife requirements. Only in this manner can we avoid the present ad hoc approach to fish protection, with its resulting problems for both fishery and power production. 15

Page III-17, paragraph e.(2). BPA should note that the FWCA provides some authority for conservation efforts, to the extent that these efforts assist in the equal treatment of fish and wildlife with other project purposes.

Page III-18, paragraph e.(3). The analysis of conservation requires more specificity. As now drafted, the 14-point BPA policy is so general that it could support a wide range of measures, including conflicting measures. The DEIS should state the kinds of "energy conservation programs" BPA would propose or encourage under its "policy." We assume that conservation includes load management directed at reducing peak power demand, through pricing or other means: this should be referenced throughout the discussions of "policies," particularly the discussion of pricing (Page III-21) and customers (Page III-19). 16

Page III-53 to 62. The statement should discuss the extent this alternative is available under existing authority. (Several aspects of the alternative seem available to BPA if a less restrictive view of its authority were taken.) 17

Page IV-10, paragraph b. The increased use of hydroelectric projects for peaking, with increased river fluctuations, is never correlated with the fishery impacts noted below. 18

Page IV-13. Paragraphs (b) and (c) are confusing; they indicate that there "may or may not" be certain efforts or impacts. For example, paragraph (b) notes that peak pricing may reduce peak demand, but does not indicate whether this approach will be implemented or even encouraged. Similarly, paragraph (c) does not indicate whether fluctuations will, in fact, be likely. 19

Page IV-13. The discussion of coordination arrangements should indicate that it might be desirable to modify existing operating agreements in furtherance of the "one-utility concept." 20

Page IV-15, paragraph 2. The Columbia River anadromous fish runs are presently in a severely depressed condition due mainly to the impact of hydroelectric development. The economic value and importance of the corresponding sport and commercial fisheries are therefore also depressed. Based on a recent 3-year 21

5

average of sport and commercial harvest, and 1977 prices, the Columbia River salmon and steelhead fisheries are valued in excess of $132 million annually. The potential value of these fisheries with mitigation implemented for the effects of hydroelectric development would be much greater. Besides the direct economic benefits of salmon and steelhead, ecological and social values to residents of the Pacific Northwest are also attributable to the anadromous fish runs (see also the Water Resources Council's "Principles and Standards"). The DEIS should be corrected to reflect these data.

Page IV-15, paragraph 3. The paragraph implies that the resident fish resource provides recreational opportunity for sport fishermen while the anadromous fish resource supplies a commercial fishery. About one-third of the salmon and steelhead harvest from Columbia River stocks is by sportsmen and the resulting sport economic value far exceeds the commercial fishery value. 22

Page IV-15, paragraph 4. The development of hydroelectric projects in the Columbia Basin is the major factor related to the decline and continued depressed state of the anadromous fish resources. 23

Page IV-16, paragraph 1. The DEIS should reflect that while many factors have combined to cause the decline of salmon and steelhead populations, hydroelectric development has had a greater, lasting adverse impact than all of the other factors combined. 24

Page IV-16, paragraph 2. All upriver stocks of salmon and steelhead are presently under review for possible action under the Endangered Species Act of 1973. 25

The State and Federal fishery agencies have historically been relatively successful in coordinating research and management amongst themselves. However, coordination between the fishery agencies and those agencies developing and controlling the Columbia River for other uses has been sorely inadequate and has consequently resulted in severe fishery losses.

Page IV-16, paragraph 5. The DEIS does not present the extent of fishery losses caused by the combination of low flows and hydroelectric projects, including long-term cumulative impacts. For example, during 1973 and 1977, two recent low flow years, over 95 percent of the outmigrating salmon and steelhead population was lost. These data should be reflected in the DEIS. 26

Page IV-17, paragraph 1. Data collected from salmon spawning grounds in the Snake River Basin have shown that the adult delays, stresses, and injury resulting from passage over the dams has resulted in greatly reduced spawning success for those fish that do survive the upstream migration. 27

Page IV-17, paragraph 2. The DEIS should indicate that flow control and fluctuations caused by hydroelectric generation have repeatedly resulted in extensive losses of emerging fry in the Snake and mid-Columbia Rivers. 28

Page IV-17, paragraph 3. As noted in our General Comments, the discussion of mitigation and compensation measures must be substantially expanded to satisfy the requirements of the CEQ guidelines. The actions BPA will implement or encourage for fisheries protection and the relative merits of these actions, including comparative benefits to fisheries, must be thoroughly discussed. 29

6

The DEIS portrays an overly optimistic view of coordination and cooperative efforts aimed at preserving and enhancing Columbia River salmon and steelhead. Coordination will not restore the fish runs so long as insufficient consideration and status are given to the requirements of salmon and steelhead by agencies controlling the operations and improvements of the hydroelectric projects. Current consideration of fishery requirements is subject to the generation of near maximum levels of power and future plans to operate the Columbia River for maximum energy production. We believe coordination will become a truly useful tool to maintain and restore fish runs only after legislative mandates require the river to be operated for multiple purposes, including fisheries.

Page IV-17, paragraph 4. The DEIS should clearly indicate that the effectiveness of turbine bypass systems and smolt transportation have yet to be determined. With turbines screened and some bypass spill provided at several dams, juvenile chinook have still sustained losses of 15 and 21 percent per project in 1978 and 1979 respectively. 30

Page IV-35, paragraph c.(2). This paragraph should describe the degree and extent of possible flow fluctuation control. 31

Page IV-35, paragraph d. There are various ways of "running the river" using a coordinated approach. These should be set out and discussed, so that relative benefits and other comparisons may be made. 32

Page IV-93, section B.1. The draft statement should discuss how "regional cooperation and coordination" would be implemented and how conflicts between power and non-power interests would be resolved. Are changes in decision-making processes anticipated for improved accommodation of environmental and other concerns? The discussion here and elsewhere fails to recognize these and related complexities affecting power system development. 33

The second paragraph of this section indicates that non-power concerns have historically been accommodated with little conflict. With respect to anadromous fisheries, this is certainly inaccurate -- the conflict between fish and power production has been long-standing, and the cumulative adverse effects on fish populations and habitat have been dramatic. 34

Page IV-94, paragraph a. This discussion seems to be the major thrust of the DEIS, yet it is dealt with only superficially. The DEIS should state the various modes or alternatives for regional cooperation and coordination which BPA is considering. The relative environmental and ecological impacts of these alternatives, including the failure to coordinate, must be thoroughly analyzed. 35

Page IV-97 to 98, paragraph (5). The opportunities provided for input from fishery and other non-power interests should be mentioned. The DEIS should expose how these opportunities will be translated into actual decisions which are responsive to non-power concerns. It is clear from past experience that input alone is insufficient. 36

For example, with respect to fisheries, power-related impacts are generally known and understood by power interests but are simply not accommodated in power decisions to the extent necessary. The reliance placed on "concensus" seems overly optimistic in light of this experience.

Letter #50 (continued)

7

Page IV-100, first paragraph. In view of the mandate of the FWCA, NMFS objects to the implication that power interests and demands will be found controlling in 37
fishery-power conflicts. Severe adverse impacts on fisheries would definitely result and, using a "worst case" analysis, could lead to extinction of some stocks. We suggest that this section explore in some detail the methods which are available to minimize fishery impacts while accommodating and/or shaping power demand, and identify those methods which BPA will adopt or encourage.

Page IV-101, paragraph c. Our comments above are equally applicable to this 38
section.

Page IV-110, section (2). The discussion of load management is too general to support informed decision-making based on the DEIS. In particular, the references to direct load control, peak pricing, and energy storage do not fully explore the range of available alternatives.

The costs of load management may be expensive when viewed in isolation, but they must be viewed in the appropriate context. These costs can only be assessed in 39
comparison with costs of new peak power generation, as well as environmental costs which will be felt without load management (e.g., the value of fishery losses due to peaking fluctuations at hydroelectric projects).

The DEIS should comment on what forms of load management BPA will adopt or encourage, and their relative environmental impacts. The discussion in Pages IV-112 to 113 does not adequately address these concerns. Without load management, for example, a "worst case" analysis of fishery impacts might indicate that upriver stocks would no longer survive.

Page IV-119, paragraph b.(1). The DEIS should review the actual hydroelectric 40
capability of the region when economic, environmental and political constraints are considered.

Page IV-120. The environmental impacts of hydroelectric operations on fisheries are inadequately explored. The cumulative impacts of existing dams should be discussed quantitatively, in terms of lost or impaired fish populations. Of course, the remaining fish habitat which would be adversely affected by new 41
hydroelectric projects would reflect an even greater relative loss in view of these cumulative impacts, since remaining habitat is more critical and valuable due to its scarcity.

Citations of supporting documentation should be provided throughout.

Page IV-122. Again, the discussion of fishery impacts is simplistic and cannot provide a basis for comparative analysis. The last paragraph, referencing lower 42
mortalities through bulb turbines, is questionable based on present data. No studies to date indicate that bulb turbine mortalities are statistically different from those associated with conventional turbines.

Page IV-187. Inherent in all five resource scenarios is the fact that hydropower will play an important tole. Since there is no mention of external factors 43
impacting present hydro operations, it must be assumed that all water sources will be obtimized for power production. We do not perceive any accommodations for fish flows which, when translated for use in this document, will mean loss of megawatts.

8

The omission of this type of data makes all of these scenarios unrealistic and therefore they cannot present a reasonable estimate of the environmental impacts and available mitigation measures.

Page IV-191, paragraph 3. The "worst case" scenarios all seem to meet the projected West Group Forecast load predictions. Historically, the West Group Forecast has been conservative in that it has projected a higher load than that 44
which actually materialized. By comparison, a "worst case" scenario for fish (other than extinction) would occur when all hydro resources are run strictly for peaking purposes, recognizing that certain navigation and flood control criteria must be met. It is important that this type of "worst case" fisheries scenario also be demonstrated and analyzed.

Page IV-192, paragraph 1. As discussed above, a "worst case" scenario for fish resources was not demonstrated in the DEIS. In this paragraph of the DEIS such a scenario is ruled out because it is not "worst case". This approach is not 45
only unrealistic, but also inadequate for review purposes. We suggest that, along with the "worst case" fish scenario, the discussion include a 'best guess" future resource scenario. If it is thought that a certain mix of resources will develop and will result in quantifiable impacts, the "worst case" scenario presented in the DEIS is virtually meaningless because as stated in the DEIS, the resources will never develop in this manner.

Page IV-192, paragraph 3 through Page IV-193, paragraph 3. A recent GAO report "Review of Peaking Power Needs in the Pacific Northwest" (EMD-80-46) cast substantial doubt on the Pacific Northwest Utilities Conference Committee's (PNUCC) 1979-99 forecast. Specifically, the report stated that the PNUCC forecast does not balance a forecasted peak load with the forecasted available resources and if they were, 46
PNUCC's forecast peak could be reduced by over 2,000 MW. This in turn would reduce the peak power deficits forecasted by PNUCC through 1989.

The GAO report also stated that the reserves for contingencies may be too conservative. Quoting directly, it states:

"Three factors contribute to this conclusion. First, loss-of-load calculations are based on the probability of no more than one expected outage in 20 years. Most utilities in other regions require a reliability of no more than one expected outage in 10 years -- a level which may still be too high, according to a recent report by the Congressional Research Service. Second, the region's planned reliability appears to have been even greater than this once-in-20-years probability, because of the conservative "rolling" criterion used for estimating system reserve requirements. Finally, over 1,000 MW of power sold by BPA to its direct service industrial customers can be interrupted at any time for any reason, and could be used as system reserves to help meet peaking needs. This reserve, however, has not been taken into account in determining the region's peaking surplus or deficit."

Finally, the GAO reported that "...although PNUCC has been reducing its projected rate of increase for peak loads, actual peak loads in the region reportedly averaged nearly eight percent below forecasted peak loads during the period 1973 to 1977."

Since this GAO report casts doubt on the PNUCC forecast, we feel that a review of the assumptions should be made and explanations provided. Even though the PNUCC forecast may present an inflated "worst case" it appears to be inaccurate and therefore of no help in trying to determine the true impacts.

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Page IV-193, paragraph 1. The conservation induced load reduction of 448 MW requires more explanation. It appears this is included to further reduce an over-estimated PNUCC load forecast. Why the PNUCC did not include this reduction 47
in their original estimates rather than as an add-on by BPA should be explained.

Page IV-193, paragraph 2. NMFS believes that more consideration should be given to peaking alternatives such as combustion turbines. This consideration is particularly important because of potential adverse impacts to fish caused by 48
river fluctuations. There is no mention in this DEIS of the possibility of coal gasification or liquification as fuel sources for peaking units.

Page IV-193, paragraph 3. One of the prime factors, if not the prime factor, for decreasing the demand for power is the cost of fuel. To omit the influence 49
of resource costs on energy demand is again unrealistic. Surely there is some trend information which can be correlated to show as resource prices go up there is an associated quantity or rate of conservation.

Page IV-193, through IV-229. Scenario A (100% Renewable Generation) adds over 15,000 MW of hydro generation or over two-thirds of the total new resources to 50
meet the PNUCC load. However, the impacts summary shows no aquatic impact, only land use effects. Any discussion of impacts must reflect the potential impact on fish.

Scenario B shows a conservation "production" of over 10,500 MW, almost 50 percent of the projected PNUCC load. The explanation of how this was achieved is not 51
comprehensible as written in Table IV-34 on Page IV-199. This is an important item and should be presented in a manner understandable to all readers. Additionally, there is an increase of over 7,000 MW of hydro capacity projected here with no discussion of impacts.

Scenarios C, D, & E also have hydro additions with no aquatic impact analysis. 52
This does not reflect the potential environmental impacts of future generation, or BPA's ability to affect the regional resource mix under the one utility concept.

The consumptive water use of the five different scenarios is an important factor which received little attention and discussion. Scenario D (100% nuclear) has the 53
largest amount of increase. Under "D" consumptive water use triples over the present operation. Scenario C (100% coal) shows only a 60 percent increase. The associated impact of this consumptive water use is not discussed. The discussions associated with these scenarios should indicate the effect of the consumptive use on streams and their fishery resources.

Page IV-230, second paragraph. With respect to fisheries, we cannot agree that existing depleted conditions are the baseline against which additional impacts 54
should be measured. Use of this baseline would institutionalize and constitute acceptance of existing operational problems in the power system, which NMFS and other fishery agencies are presently seeking to improve. A better "baseline" would be optimum production levels of both fisheries and power.

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Page IV-231, second paragraph. We question the statement indicating that if the PNUCC forecast is in error, then environmental impacts will be less severe. 55
In fact, if new and increased generation capability is tied to the PNUCC forecast, many adverse environmental impacts will not be avoided even if demand falls below forecast levels. A more realistic approach would be to develop an accurate forecast of demand which incorporates strong conservation and load management programs, and which will help to minimize adverse environmental impacts through proper planning.

Page IV-235, paragraph (2), and Page IV 243, paragraph (3). As noted here, BPA 56
has substantial ability to influence the energy development patterns for the Northwest. How BPA will use this influence to minimize adverse environmental impacts associated with energy development is pertinent to the DEIS. The steps BPA could take in this regard, and their relative environmental impacts should be thoroughly explored.

Page IV-260 to 261, paragraph (2). The DEIS should discuss the kinds of peakload 57
management BPA will propose (if any). The environmental and ecological impacts which can be expected with various levels of peakload management, or if no such management is instituted, needs to be explained.

Page IV-263, paragraph (5)(a). This section gives no clear indication of what 58
BPA proposes to undertake. For example, in the second paragraph, there is no way to assess whether or not BPA intends to initiate peakload management.

The use of vague terms and conclusory statements in this and the following sections obscures the distinction between the proposal and the alternatives. Theoretically, it seems that BPA could put together almost any program and consider it to fall under any one of the alternative "roles" described in the DEIS.

Page IV-274 to 277. Please refer to our comments for Pages IV-17, and IV-93 59
to 101 regarding fishery-power conflicts.

Page IV-313 to 330. Our comments throughout would apply to the appropriate conclusions in this Summary Section. Additionally, it is worth noting that litigation is almost certain if fishery interests are not reflected in power planning and operations. A coordinated regional power system which does not 60
provide for improved accommodation of fishery interests will not decrease the likelihood of such litigation.

We appreciated the opportunity to provide our comments. Because our comments raise such significant question on the adequacy of the DEIS, we believe that it must be revised and subject to further review. We would be pleased to provide pertinent fisheries data upon request.

CLEARANCE: SIGNATURE AND DATE:

F/HP:JWRote ________________________________

Letter #51

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June 12, 1980

John E. Kiley
Environmental Manager
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

Dear Mr. Kiley:

As promised in our phone conversation of this date, I attach NRDC's comments on BPA's revised draft environmental impact statement, The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System.

I also enclose, as a supplement to those comments, NRDC's revised Alternative Scenario for the Electric Energy Future of the Pacific Northwest. I reemphasize that this document represents the views of NRDC, and not necessarily those of the U.S. Department of Energy.

It is my understanding from our conversation that both of these documents will receive full consideration as BPA undertakes to revise the draft EIS.

Yours sincerely,

Ralph Cavanagh

Ralph C. Cavanagh

RCC:as
Enclosures

P.S. The Department of Energy has asked that we not release the Scenario until agency personnel have had a chance to comment. Accordingly, we request that for the present you limit your use of the document to the EIS revision process.

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COMMENTS

OF THE

NATURAL RESOURCES DEFENSE COUNCIL, INC.

ON THE

BONNEVILLE POWER ADMINISTRATION'S

REVISED DRAFT ENVIRONMENTAL IMPACT STATEMENT

"THE ROLE OF THE BONNEVILLE POWER ADMINISTRATION IN THE PACIFIC NORTHWEST POWER SUPPLY SYSTEM, INCLUDING ITS PARTICIPATION IN A HYDROTHERMAL POWER PROGRAM"

Ralph Cavanagh

June 12, 1980

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I. Introduction

These comments are submitted by the Natural Resources Defense Council in response to a Revised Draft Environmental Impact Statement entitled "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System, Including Its Participation in a Hydro Thermal Power Program" (hereinafter "Role EIS"). We have concluded that the EIS fails to comply with the mandates of both the judicial order under which it was prepared and the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4321 et seq. Extensive revisions, and resubmission for public comment, are necessary to remedy the deficiencies of the document.

Accompanying these comments is a revised draft of NRDC's Alternative Scenario for the Electric Energy Future of the Pacific Northwest (hereinafter "NRDC Scenario"). The Scenario affords the technical underpinning for many of our criticisms of the Role EIS, and points the way toward the comprehensive analysis of realistic alternatives to existing policies that is so conspicuously lacking in the Role EIS itself.

The starting point for review of the Role EIS is the judicial decision compelling its preparation. Bonneville apparently construes that decision as a directive to evaluate the so-called "one utility concept," a centralized planning philosophy, without reference to the inventory of energy resources that is likely to emerge from the planning process. The result is an extended celebration of coordinated resource and transmission planning, in which the region's future resource mix is treated as an exogenous 1

variable largely unknowable and outside BPA's control.

But NRDC v. Hodel was not a challenge to centralized planning per se, nor was the judicial opinion that the lawsuit engendered concerned primarily with abstract questions of interutility coordination. Rather, the court addressed and enjoined BPA's unlawful effort to evade NEPA requirements in the course of acting to facilitate a regional electric energy system with the following characteristics:

> Baseload power will depend increasingly upon thermal generating resources, while peaking power will be provided by hydroelectric resources. The utilities will build the required thermal power plants. BPA will provide the necessary peaking capacity and high-voltage transmission grid, along with reserves, load shaping, sale of surplus power, and scheduling of project output.

435 F. Supp. 590, 597 (1977).

This and subsequent passages make clear that the "major federal action" at issue, for purposes of this EIS, is not the concept of "one-utility" planning but the transmission facilities, power plants, hydropower adjustments, and other actions involved in a major shift to thermal supply resources under a "one utility" approach. See, e.g., 435 F. Supp. at 598-99. Under the circumstances, the goals of this EIS were clear from the outset. BPA should have addressed "reasonable alternatives" to new thermal power plants for meeting the region's electricity needs, incorporating a detailed analysis of "[e]nergy requirements and conservation potential of various alternatives and mitigation measures" and "[n]atural or depletable resource requirements and conservation potential of various alternatives and mitigation measures." 43 Fed. Reg. 55978, 55996 (1978) (Council on Environmental Quality, National

Environmental Policy Act - Regulations, § 1502.14).

The EIS does contain alternative scenarios for meeting the region's electricity needs, but these are relegated to a subordinate role, presented as "worst case" analyses that are "exceedingly unlikely" to materialize (IV-218), and excluded altogether from the discussion of alternatives to the BPA proposal. The only "alternatives" reviewed in the EIS are "differing levels of regional cooperation and coordination or alternative approaches to the 2
one-utility concept" (i). The "future power resource mix" for the region -- which ought to be the crux of this document -- is dismissed as an "unresolved issue" (vii). Left unanswered -- and largely unconsidered -- is the critical question that BPA itself poses at the outset of the document (I-1):

> What is the best practical way to meet future regional electric energy demand cost-effectively, to avoid the social and economic costs of energy shortages, to minimize adverse environmental impacts, and to conserve nonrenewable resources?

BPA is content to respond to that query solely in process terms: highly centralized planning is best, somewhat centralized planning is next best, uncoordinated planning is least desirable. But coordinated planning is not an end in itself; it cannot generate or transmit or conserve a single kilowatt of electricity, nor can it create or avoid significant environmental impacts. <u>NRDC</u> v. <u>Hodel</u> was not a lawsuit calling into question the virtues of coordinated electric energy policy-making, nor was the court's order directed exclusively or primarily at efforts to eliminate redundancy in resource and transmission systems. The main issue was and remains one of substance, not procedure, going to how the region's future

electricity needs will be met.

We enumerate, in the sections that follow, a number of specific inadequacies in the Role EIS. At the heart of many of these problems is BPA's attempt to deflect this document away from what should have been its primary concerns.

II. <u>The BPA Proposal is Unacceptably Vague</u>

According to its authors, the BPA proposal "is straightforward and simple: proceed expeditiously to do the best that can be done under existing authority to solve the region's energy problems (I-27)." Efforts to translate this straightforward and simple proposal into concrete implications for resource development 3
are doomed at the outset, however, because a crucial ingredient is missing: a comprehensive regional load forecast and power planning document prepared and endorsed by BPA. The agency expressly indicates its ability and intention to prepare such materials (III-13 to III-15), but is content to leave their completion to an undisclosed future date. The Role EIS simply cannot defer these crucial issues. What BPA describes at page III-14 as a goal of its "proposal" is precisely what this document is supposed to accomplish:

> an assessment of regional power problems; an analysis of possible solutions to identify the most effective, economical, and environmentally sound means of meeting these problems; proposals for BPA action within its existing authority which would mitigate or solve these problems; and proposals identifying regional cooperative actions which could be taken by utilities and States.

Until BPA has done precisely that, it cannot claim compliance with NEPA or the order in <u>NRDC</u> v. <u>Hodel</u>. The reader is left completely uncertain as to BPA's position regarding the region's

future thermal power needs. A definitive statement, based on an independent analysis, can and must be forthcoming from a body charged with carrying out "administration policy to use the assets of the Federal power system . . . to satisfy future power needs in the most economic and environmentally sound manner" (IV-251).

The reader's uncertainties are compounded by the proposal's amorphous "conservation" element. BPA's options for encouraging cost-effective conservation are discussed at length in the NRDC Scenario at pages 226-251. One of the most important of those options is a conservation-oriented allocation policy; yet the BPA proposal 4
is content to defer allocation issues: "Because BPA is preparing a specific EIS on its proposed allocation policy, it would be inappropriate to include in this statement any definite proposal regarding allocation." (III-27) This is a legally and logically impermissible evasion. Programmatic EIS's may not ignore otherwise relevant issues on the ground that they are or will be covered in more narrowly focused documents. Otherwise, the relationship among program elements and options could be lost in a welter of fragmented analyses. The Role EIS should address BPA's allocation proposal <u>and</u> reasonable alternatives, such as that proposed by NRDC in a December 14, 1979 filing with the agency. The importance of this inclusion is highlighted by BPA's repeated allusions in the Role EIS to the impossibility of quantifying the regional impact of its conservation proposals; allocation plans can be readily keyed to specific reductions in demand growth,

as both the current BPA allocation proposal and the NRDC alternative make clear. The impact of such programs can be predicted with far more confidence than, e.g., "encourag[ing] more ambitious conservation programs by all electric utilities in the region". (III-21)

BPA does offer a "14-element" conservation policy, but it is couched exclusively in platitudes. BPA "recognizes that electrical energy saved through conservation is . . . valuable"; acknowledges that opportunities for conservation exist; "would offer technical, administrative and <u>possibly</u> financial assistance to its utility customers to carry out conservation programs" (emphasis added); intends to exhort the region to conserve; "would consider" incor- 5
porating conservation incentives in rates and energy allocations; and "would strive for a coordinated regional approach to conservation." (III-19 to III-22) No investments are specified by amount or projected impact; no actual conservation incentives are proposed. BPA calls only for "consideration" of a laundry list of equally amorphous initiatives, set out at III-24 to III-25. In sum, BPA presents no "conservation policy" in its proposal -- only tantalizing hints that such a policy may soon be forthcoming. BPA should specifically describe the expenditures and incentives it is considering and/or intends to adopt, and assess their likely impact on regional demand growth. The Role EIS as written incorporates an explicit acknowledgement of BPA's complete abdication on these points: "Because of the general nature of the proposal and a current lack of useful data related to regional energy consumers and uses, it is virtually impossible to determine with confidence how much

energy conservation potentially or actually could be accomplished in the region if BPA's proposal were realized." (IV-234) BPA has had five years to remedy both of the deficiencies identified in that statement.

III. <u>The Analysis of Alternatives is Totally Inadequate</u>

An EIS must contain a detailed analysis of the environmental impacts of "alternatives to the proposed action." NEPA, 42 U.S.C. § 4332(2)(C)(iii). The importance of this requirement has been recognized by the courts and CEQ as well as Congress. The CEQ Regulations, for example, refer to the alternatives section as "the heart of the environmental impact statement." § 1502.14. Those regulations require that agencies "shall":

> "(a) Rigorously explore and objectively
> evaluate <u>all</u> <u>reasonable</u> <u>alternatives</u>, 6
> and for alternatives which were elim-
> inated from detailed study, briefly
> discuss the reasons for their having
> been eliminated." § 1502.14(a)(emphasis supplied).

The consideration and discussion of alternatives has been justly termed the "linchpin of the entire impact statement." <u>Monroe County Conservation Council</u> v. <u>Volpe</u>, 472 F. 2d 693, 697-98 (2nd Cir. 1972). The alternatives requirement has two fundamental objectives: (1) to force agencies to consider all reasonable approaches to an action, <u>see</u>, <u>e.g.</u>, <u>NRDC</u> v. <u>Morton</u>, 458 F. 2nd 827, 836 (D.C. Cir. 1972); and (2) to inform the public what those approaches are, in order that they may comment upon them. <u>See</u>, <u>e.g.</u>, <u>California</u> v. <u>Bergland</u>, Civ. No. 79-523 (E.D. Ca., summary judgment granted Jan. 8, 1980), Opinion and Order at 42. "Only in this fashion is it likely that the most intelligent,

optimally beneficial decision will ultimately be made." <u>Calvert Cliffs' Coordinating Comm.</u> v. <u>AEC</u>, 449 F. 2nd 1109, 1114 (D.C. Cir. 1971). <u>See</u> <u>also</u> CEQ Regulations § 1500.1(c).

In order to fulfill these objectives, agencies are under an affirmative obligation to seek out and explore the wisdom of alternative courses of action. <u>See</u> <u>Rankin</u> v. <u>Coleman</u>, 394 F. Supp. 647, 658 (E.D. N.C. 1975).* The EIS must examine all obvious and logical alternatives. <u>Brooks</u> v. <u>Coleman</u>, 518 F. 2d 1719 (9th Cir. 1975). It must discuss a range of reasonable alternatives. <u>See</u>, <u>e.g.</u>, <u>California</u> v. <u>Bergland</u>, <u>supra</u>, Opinion and Order at 42; <u>Movement Against Destruction</u> v. <u>Volpe</u>, 361 F. Supp. 1360, 1388 (D.C. Md. 1973); CEQ Regulations, § 1502.2(e). <u>Cf</u>. <u>Greene County Planning Board</u> v. <u>F.P.C.</u>, 559 F. 2d 1227, 1232 (2d. Cir. 1976)("The purposes of NEPA are frustrated when considerations of alternatives and collateral effect are unreasonably constricted."). Agencies must justify the range of alternatives considered and explain why it is believed to be reasonable. <u>California</u> v. <u>Bergland</u>, <u>supra</u>, Opinion and Order at 47. Finally, as noted earlier, the CEQ regulations require, in the context of energy projects, specific attention to the

*That Congress attached particular importance to agency consideration of alternatives is demonstrated by NEPA itself. A thorough analysis of alternatives to recommended courses of action is required not only when the preparation of an EIS is undertaken pursuant to § 102(2)(C), but also whenever a proposal "involves unresolved conflicts concerning alternative uses of available resources." 42 U.S.C. § 4332(2)(E). This section expressly demands that agencies "study, develop and describe" all appropriate alternatives to proposed actions even apart from the EIS process. The § 102(2)(E) duty to consider alternative courses of action has consistently been viewed by the courts as being "independent of and of wider scope than" the duty under § 102(2)(C) to file an EIS. <u>NRDC</u> v. <u>Callaway</u>, 524 F. 2d 79, 93 (2d Cir. 1975); <u>Trinity Episcopal School</u> v. <u>Romney</u>, 523 F. 2d 88, 93 (2d Cir. 1975); <u>Nucleus of Chicago Home-owners Ass'n</u> v. <u>Lynn</u>, 524 F. 2d 225 (7th Cir. 1975).

"conservation potential of various alternatives." 43 <u>Fed</u>. <u>Reg</u>. 55978, 55996 (1978). When BPA states (I-23) that "it would seem useful to readers and decisionmakers alike to be able to identify a maximum credible regional and BPA energy conservation scenario," the agency is describing an affirmative obligation, not simply identifying an intriguing discussion topic.

These nondiscretionary responsibilities have not been discharged in the Role EIS. One of the most fundamental problems has already been cited: BPA has misconceived the scope and purpose of the document, centering discussion on varying levels of interutility cooperation as opposed to the various "resource mixes" toward which such cooperation is or could be directed. The Role EIS contains some discussion of conservation and renewable energy resources, but on two critical levels it falls woefully short. First, it omits any detailed analysis of BPA's options under existing legislative authority to promote such policies. Second, it does a superficial and completely inadequate job of projecting the potential for cost-effective conservation and renewable resource applications in the region.

A. <u>BPA's Existing Authority to Promote Conservation and Renewable Energy Resources</u>

BPA's proposal, reviewed earlier, contains a list of vaguely described measures that the agency intends to consider implementing
under its existing legislative authority (III-24 to III-25). Men- 7
tioned, <u>inter alia</u>, are (1) financial assistance for utility conservation programs; (2) adjustments in the rate structures of both BPA and the utilities it serves; (3) audit and other programs to encourage commercial and industrial conservation; (4) BPA "purchases"

of energy saved through conservation measures; (5) allocation of federal power pursuant to conservation requirements; and (6) "BPA enforcement of conservation requirements through contract provisions." Either the proposal or an alternative must analyze the full extent to which BPA can press each of these measures to promote cost-effective conservation (under which rubric we include renewable resource applications at points of end use), and estimate the regional impact in terms of reduction in demand for central station electricity. By leaving these questions unaddressed, the Role EIS evades the clear mandate of the CEQ Guidelines and eviscerates its utility as a decision-making guide. BPA has failed utterly to deliver "a maximum credible . . . BPA energy conservation scenario. . . . " (I-23) That some possible BPA actions, such as rate design and allocations, are slated for discussion in other EIS's is no excuse for ignoring them in a programmatic document that is supposed to serve as a comprehensive guide to the formulation of regional electric energy policy.

We note that the U.S. General Accounting Office has recently endorsed, in principle, BPA's adoption of two-tiered wholesale rates; GAO has also made clear its view that BPA has statutory authority to invest in conservation measures if "the Administrator, on a
reasonable basis, determines conservation to be a desirable device 8
for discharging his transmission and marketing functions, and includes projected expenditures therefor in his annual budget submitted to the Congress."** If BPA disputes either of these positions, it should

**See letter, dated July 10, 1979, from Elmer R. Staats, Comptroller General, GAO to Hon. Jim Weaver at p. 5; letter, dated February 6, 1980, from J. Dexter Peach, GAO, to Hon. Jim Weaver.

Letter #51 (continued)

to so openly in the EIS.

3. <u>Regional Potential for Cost-Effective Conservation and Renewable Resource Applications</u>

The Role EIS proclaims on numerous occasions that Phase 2 of the Hydro Thermal Power Program is defunct. But the EIS identifies no less than nine thermal plants "committed subsequent to Phase 1 of the HTPP" (IV-35), and BPA's proposal calls for extension of

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load factoring, transmission, and other services to Northwest utilities "to integrate new and existing non-Federal generating resources into the Federal Columbia River Power System (FCRPS) for their use." (III-8) This recalls the admonition of the court in <u>NRDC</u> v. <u>Hodel</u>:

> I do not regard the label "Phase 2" as some sort of talisman crucial to the plaintiff's case. Thermal plant locations are likely to change, new methods for financing their construction may be devised, and a way may yet be found to provide BPA's direct-service industrial customers with low-cost power after their present contracts expire. So long as these modifications do not change the basic concept of the HTPP, however, a programmatic EIS must be completed before BPA undertakes any further action to implement Phase 2. 435 F. Supp. at 602.

That programmatic EIS must consider alternatives to the nine "federalized" plants, and specifically, must assess the possibility that some or all could be displaced by cost-effective and environmentally preferable conservation measures and renewable energy resources.

The only element of the Role EIS that is remotely relevant on this crucial point is the so-called "Scenario B" for future power resources, which "assumes maximum conservation, including the use of mandatory measures, with any remaining loads met

through end-use renewable resource development." IV-187)

Scenario B's conservation estimates are drawn exclusively from a 1976 study by Skidmore, Owings and Merrill that BPA characterizes as "the best available for the BPA service area" although it was "prepared in 1976 when little information was available about energy conservation measures" (IV-236) and is now "out of date" (IV-105). BPA altogether ignores five extensive analyses of regional conservation potential prepared since 1976. One of these omissions, the 1980 NRDC Scenario, is understandable since the document is only now available; we trust that it will receive full consideration as BPA undertakes the task of revising the Role EIS. But a failure to even cite the other four studies in the description of Scenario B is inexplicable. They are as follows:

1. Natural Resources Defense Council, Inc., <u>Choosing An Electrical Energy Future for the Pacific Northwest: An Alternative Scenario</u> (1977).
2. TRW Energy Systems Planning Division, <u>Evaluation of Electric Power Alternatives for the Pacific Northwest</u> (1977).
3. U.S. General Accounting Office, <u>Region at the Crossroads - The Pacific Northwest Searches for New Sources of Electric Energy</u> (1978).
4. U.S. General Accounting Office, "Hypothetical Transfer of Construction Funds From Nuclear Power Plants to Electricity Conservation and Renewable Energies" (EMD-80-71, 1980)(concluding that the region could save money by mothballing the WPPSS 4 and 5 plants, which are already under construction, and using part of the funds that would be needed to complete them to invest in equivalent amounts of conservation and renewable resources).

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Failure even to discuss these documents, each of which attests the extensive potential impact and cost-effectiveness of specific conservation measures and renewable resource applications, renders extremely suspect BPA's repeated dismissals of the possibility that such measures can obviate the necessity for new thermal generation in the region over an extended period. In this regard, it is revealing that BPA does not even attempt cost comparisons among the five scenarios; both the GAO and TRW studies can be drawn on for that purpose, and both show convincing cost advantages for conservation scenarios over central station alternatives. In revising the Role EIS, BPA should give far more attention to cost issues, and should update the obsolete and incomplete thermal power plant cost estimates now set out at IV-49.

In addition, to make possible an adequate assessment of alternatives to the BPA proposal, the Role EIS should specifically address the proposals incorporated in the attached NRDC Scenario. The key distinction between the NRDC Scenario and Scenario B is noted in the Role EIS itself: "the NRDC scenario is portrayed as an achievable development, whereas Scenario B and the other scenarios have been designed as improbable extreme cases...." (III-4) Precisely because it constitutes a reasonable, comprehensive and environmentally preferable alternative to the expanded thermal power base implicit in the BPA proposal, the NRDC Scenario deserves

consideration in the EIS process. It is BPA's failure to explore <u>any</u> reasonable alternatives to the thermal plants it proposes to integrate into the region's power grid that renders this EIS inadequate on its face. It should be noted that, unlike its predecessor, the 1980 NRDC Scenario contemplates no change in the industrial mix of the region, and hence cannot be dismissed as a program of action "outside of BPA's statutory authority." Also, contrary to BPA's assertions at pages III-4 and III-5, both NRDC Scenarios -- and in particular the latest -- emphatically do present "an institutional program for the Pacific Northwest region," and specify "the implementing actions required of government agencies, private organizations, and individuals in order to achieve the projected regional potential." See pages 119-256 of the attached NRDC Scenario.

The conclusion of the NRDC Scenario -- which BPA cannot ignore consistent with its responsibilities to prepare an adequate EIS -- is that only four of the plants now planned or under construction are needed to
11 meet regional demand through at least 1995, if feasible and cost-effective conservation and renewable resource initiatives are pursued. Among the units that could be mothballed under the NRDC Scenario are the WPPSS 4 and 5 units, which are <u>included</u> in BPA's "maximum conservation" Scenario. BPA should note that in most instances the NRDC Scenario does <u>not</u> presume universal adoption of particular conservation measures; indeed, the Scenario incorporates a number of conservatisms, which are identified at pages 19-22, 79-82, and elsewhere.

Letter #51 (continued)

IV. Conclusion

The basic defect of the Role EIS is that it is written on the wrong subject. The document focuses on environmentally neutral management issues, rather than resource development alternatives. Since it asks the wrong questions, the Role EIS is of minimal use as a planning document. It should be rescoped, restructured, rewritten, and resubmitted for public comment. 12

After analyzing a range of realistic supply and demand alternatives for the Northwest's electric energy future, the document should explicitly select the environmentally preferable case and outline a detailed BPA program designed to promote it. If BPA wishes to pursue a different course, it should enumerate its reasons for doing so. See 43 Fed. Reg. 55978, 55996, 55999 (CEQ Regulations §§ 1502.14, 1505.2) Off-hand suggestions that the regional potential for cost-effective conservation and renewable resources cannot displace some or all of the post-Phase I facilities (e.g., IV-239, IV-244, IV-258), fly in the face of the extensively documented findings of the NRDC Scenario. We emphasize our position that these findings must be squarely confronted in the revised EIS, not simply reported without comment in an addendum to the document.

The Role EIS portrays BPA as a passive captive of unpredictable external events, as far as resource development is concerned. This contention was decisively rejected in NRDC v. Hodel, and the attempt to resurrect it in the Role EIS constitutes a misconceived effort to evade the clear import of the injunction entered by the court. The NRDC Scenario, and these comments, have enumerated the numerous options

available to BPA to decisively influence the future direction of regional electric energy policy. The Role EIS can and must be revised to permit a meaningful exploration of those options.

Letter #52

June 14, 1980

The Bonneville Power Administrations Role in the Pacific Northwest Power Supply System—Comments on Revised Draft Environmental Impact Statement.

The assumption is made that expanding Bonneville Power Administration's role in the northwest is necessary to enable a full development of conservation. I do not agree with this outlook and feel strongly that shrinking the responsibilities for Bonneville and addressing planning and implimentation of conservation techniques should properly be handled first by the state entities involved and reach co-operation in supply and transmission within the region only after the people of the respective states have had the opportunity to explore the role of conservation and renewable energy development.

Key to this concept is that closer to home consideration will elevate environmental concern.

New generation be it coal or nuclear thermal or hydro peaking is not an answer to our energy dilemma. This course of action will only serve to exacerbate the problem of wasteful end use of electricity and sky rocketing energy costs, and it is the most damaging course environmentally.

The answer to the energy dilemma lies in the direction of exploring and implementing all conservation techniques and investing in renewable small scale technologies. As an example of innovative thinking applied to the problem, recently a midwest electric co-op has offered 10% discounts

on electric utility bills to people who install solar space and water heating systems. This is the kind of incentive that will enhance the impetus to act on renewable energy opportunities.

The growth projections and need forecasting for electric supply have not factored in conservation or renewable energy development. If instead of expanding the supply of electricity, conservation methods are implemented, then enough energy would be freed to meet load growth requiremente for the short term.

In the long term we must develop renewable energy systems like photovoltaics, small scale wind, passive and active solar space and water heating and diminish our dependence on central station facilities which necessitate transmission corridors and loss for us the added efficiency of co-generation and district heating at the load centers which mid-scale conventional site specific generation would afford.

I do not believe that expanding B.P.A.'s role will in any way enhance development in the direction that must be taken, toward a decentralized, alternatives based energy system.

I believe that the states involved should have the responsibility to respond to their unique opportunities and needs and further that the light metals industry is an irresponsible wasteful use of resources and certainly should not be encouraged to expand-rather should address recycling and allow the beverage industry to switch to glass returnables through economic necessity. A vigorous public relations campaign for recycling will take care of the public response.

Letter #52 (continued)

3.

If we can honestly assess where we are and where we want to go then the choices will be clear to people and they will naturally choose the proper actions.

The kind of propaganda and public relations work that is being pursued by the utilities is counter-productive and destructive of values that we all need to make the correct choices and to survive.

Thank you for this opportunity to participate. You must realize that my beginning point of reference is that we are overtaxing the earth's capacity to sustain our life support system, I do not wish to see a furtherance of this kind of environmental damage and I feel very strongly that it is time to make a transition to a renewable energy base.

Barbara D. Rhodes
Rt 1 Route 1, Box 1945
Libby, Montana 59923

Letter #53

U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION X
1200 SIXTH AVENUE
SEATTLE, WASHINGTON 98101

REPLY TO ATTN OF: M/S 443

JUN 17 1980

Jack Kiley, Environmental Manager
Bonneville Power Administration
U.S. Department of Energy
P. O. Box 3621
Portland, Oregon 97208

Dear Mr. Kiley:

The Environmental Protection Agency has completed its review of the Revised Draft Environmental Impact Statement (RDEIS) on the Role of the Bonneville Power Administration (BPA) in the Pacific Northwest Power Supply System. The RDEIS represents a substantial improvement over the original draft environmental impact statement which the Agency reviewed in 1978. Within the recognized institutional and policy constraints that apply to every EIS, it provides a relatively objective and thorough evaluation of the environmental consequences of the alternative roles which BPA might play in the future development of the region's electric power supply system.

Many of the issues which we raised in our comments on the original EIS have been adequately addressed. However, two of the issues raised in those comments, dated 15 February 1978, need further attention in the Final Role EIS (FEIS hereafter). These issues are the "factors which affect power supply system development needs" and the "management of the Columbia River and its tributaries." The concerns expressed below derive from our broad responsibility under Section 309 of the Clean Air Act to evaluate the environmental acceptability of proposed Federal actions. They reflect (1) information in both the original EIS and the RDEIS, (2) changes in the regional and national energy situation which have developed since the original EIS was reviewed, and (3) additional evaluation work that our EIS Review Team has done on the region's energy and natural resource management issues.

Factors Affecting Power Supply System Development Needs

Like the DEIS, the RDEIS presents five electrical energy supply system 1
development scenarios for the next twenty years. These give the reader

2

a sense of the types of issues with which power planning entity(ies) will have to deal and the types of environmental consequences which can result from power planning decisions.

Our main concern is that the evaluation appears to be predicated solely on a supply based concept of the regional electrical energy situation. The five scenarios that summarize the substance of the study imply that conservation is merely an institutional and technological option for filling capacity shortfalls. We believe that this position does not reflect the potential realities of the 1980's and beyond. In our view, conservation is rapidly becoming a price-induced necessity in the Pacific Northwest as well as in the rest of the nation. The FEIS should give this point appropriate attention. The load and resource projections described in the RDEIS assume that the growth rates in electrical energy demand which the region experienced between 1972 and the present will continue into the 1980's and 1990's. They project a demand growth rate of approximately 3.5% per year. We believe that this assumption results in a significant overestimation of demand and therefore an inaccurate picture of the likely development scenarios, decisions, and environmental consequences with which the power planning entity(ies) will need to deal.

Our belief that electrical energy demand growth rates will continue to shrink rapidly during the next decade is based on several facts. The growth rate between 1972 and 1979 was positively affected by two non-recurring factors. During the Arab oil embargo and the coincident Canadian gas delivery cutback there was significant regional conversion to electricity because its supply was more dependable. At the same time, electricity prices, based primarily on fixed capital already in place, lagged behind the rate of price increase for other forms of delivered energy. As a consequence, the relative rate of electricity demand growth was supplemented by significant industrial and residential conversions to electricity. Finally, electricity rates did not reflect the effect of the five Washington Public Power Supply System (WPPSS) nuclear plants, as they come on line during the 1980's.

The most likely scenario over the next decade is a reversal of the relative cost advantage of electricity in the region, linked to an overall reduction in unit use of all forms of energy. As each new nuclear and coal plant comes on line it will force rates up sharply. This effect will be magnified by the regional practice of excluding interest during construction from utility rate bases. This scenario is already developing. In December 1979 BPA had to increase its wholesale power rates by approximately 90% to reflect, largely, the costs of the "net-billed" nuclear and coal fired power plants that are operating or under construction. Also, BPA recently announced that it will shortly have to propose a 50% rate increase to reflect further cost increases.

3

It is our belief that these continuing large rate increases will mandate consumer conservation. As a result, the probability of underbuilding the supply system becomes rather small. Conversely the probability of overbuilding, due to rapid implementation of conservation by consumers, becomes rather large. Power planning entity(ies) may then have to deal with the social, economic, and environmental consequences of overbuilding and the potential secondary effects which could result from utility efforts to sell surplus power.

We believe that this scenario merits discussion in the FEIS. It is our view that the institutional structure which the region selects to carry out its power planning must recognize and productively address conservation as a price-induced necessity. Otherwise, we may continue to have significant difficulties in developing implementable regional and sub-regional power plans that match future power loads with future power resources in an environmentally sound and cost-effective manner.

Management of the Columbia River and Its Tributaries

The discussion of the competition among power and nonpower uses of the Columbia River Systemaddresses, in part, the concerns which we expressed 2
in our review of the original draft EIS. Specifically, the RDEIS describes possible future developments of nonpower uses of the river system and the current and developing conflicts among those uses.

Our main problem lies with the manner in which the RDEIS integrates the discussion of nonpower uses with the evaluation of the alternative power planning institutional structures under consideration. The focus of that analysis is on how nonpower interests could affect the decision making of the new power planning body under consideration (or BPA if no legislation is enacted). That discussion implies that the new planning entity(ies) would have ultimate control over the management of the Columbia River System.

This philosophical approach fails to recognize the relative importance of the nonpower uses of the Columbia River System. We attach a high degree of importance to these uses because, often, there is no other large scale riverine system that could support them. The fisheries, irrigation, recreation, and domestic water supply users of the Columbia River, in large part, have no reasonable alternative resource base to support these activities.

The FEIS, therefore, needs to contain a substantially revised and expanded discussion of management alternatives for the Columbia River System and the relationship of those management alternatives to the power planning institutional alternatives under consideration in the EIS. This discussion should:

Letter #53 (continued)

1. describe the implementation status of the fisheries mitigation measures required by Federal Energy Regulatory Commission licenses for the mid-Columbia dams and the investor owned utility dams on the Columbia's tributary streams;

2. identify the existing institutional arrangements for Columbia River management, discuss how they work and their effectiveness, and evaluate how the alternative power planning structures under consideration would fit into these management structures; and

3. discuss possible changes in these river management institutional structures that could improve their effectiveness.

We would like to suggest one alternative which merits examination in this discussion. This is the legislative creation of a new inter-state Columbia River System management agency. This agency could be charged with planning for all of the uses of the river system with a Congressional mandate on the balancing of different power and nonpower uses of the river system. For example, Congress might include statutory language that directed the agency to account for the presence or absence of comparable alternative resources that could support particular uses in the balancing process.

We recognize that this suggested analysis could be viewed as a substantial expansion in the scope of the EIS. However, it is our understanding, from our observations of the Congressional deliberations and from discussions with your staff, that the principal obstacle to enactment of the Pacific Northwest power planning legislation is the continuing dispute among power and nonpower users of the Columbia River System. Given that the principal focus of the EIS is the evaluation of legislative alternatives, it is appropriate that the FEIS examine, in some detail, the major issue in the debate.

Based upon our review of the RDEIS we have rated it LO-2, (LO - Lack of Objections, 2 - Inadequate Information). By this rating we mean that we have no environmental objections, at this time, to either the BPA proposal or the two legislative alternatives examined in the RDEIS. We believe that better decisions will be made if the FEIS devotes more attention to the Columbia River management issue. This rating will be published in the Federal Register in accordance with our responsibility to inform the public of our views on proposed Federal actions, pursuant to Section 309 of the Clean Air Act, as amended.

We would be glad to answer any questions that you may have about our suggestions and concerns. In order to arrange such discussions, you may contact Daniel Steinborn, Leader of our EIS Review & Energy Policy Teams, at (FTS) 399-1285.

Sincerely yours,

Elizabeth Corbyn

Elizabeth Corbyn, Chief
Environmental Evaluation Branch

Letter #54

STATE OF WASHINGTON
Dixy Lee Ray
Governor

DEPARTMENT OF ECOLOGY
Mail Stop PV-11
Olympia, Washington 98504
206/753-2800

June 13, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621-SJ
Portland, Oregon 97208

Dear Sir:

We have undertaken a limited review of the Revised Draft Role EIS. In general, the document is a clear, well-written summary of the issues, alternatives, and impacts related to BPA's role in the Pacific Northwest. We are particularly pleased with the vigorous conservation program that BPA plans to carry out under its proposed program, even in the absence of further Congressional action to mandate such activities. The 14-point energy conservation policy appears to be an especially significant step forward in guiding balanced development of the regional energy system.

Several comments relating to specific items in the document are attached.

Thank you for the opportunity to comment.

Sincerely,

Fred D. Hahn

Fred D. Hahn
Assistant Director
External Affairs

FDH:me

Attachment

SPECIFIC COMMENTS ON

REVISED DRAFT BPA ROLE EIS

Page		
IV-7	Table IV-2. The data shown for number of units and capability of Rock Island Dam appear to be incorrect. Our figures show that Rock Island has a total nameplate rating of 620 megawatts with 18 units now complete.	1
IV-17	The third paragraph on this page should include mention of the Washington Department of Ecology's significant efforts to develop an Instream Resource Protection Program. Administrative regulations implementing the state's policy are scheduled for an adoption proceeding on June 23, 1980.	2
	The fourth paragraph on this page conveys the false impression that the various fish protection measures mentioned have been fully deployed such that fish passage problems have been largely solved. Turbine screens and bypass systems have only been installed to a very limited extent to date; artificial transportation systems are viewed by fisheries agencies as only a temporary solution to certain downstream migration problems; manipulation of storage reservoirs to provide flow and spill for fish is the subject of continuing controversy — in this regard, it would be appropriate to mention the recent FERC settlement agreements regarding operation of the mid-Columbia PUD dams.	3
IV-67	The last paragraph should include documentation of the predictions of the decrease in loads resulting from the 90 percent revenue increase. These figures imply an extremely low price elasticity of demand for BPA's electric power.	4

Letter #55

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

JUN 13 1980

Mr. John E. Kiley
Environmental Manager
Bonneville Power Administration
P. O. Box 3621 - SJ
Portland, Oregon 97208

Dear Mr. Kiley:

This is in response to your request for comments on the Draft Environmental Impact Statement concerning "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System, Including its Participation in a Hydro-Thermal Power Program".

We have reviewed the statement and determined that proposed action has no significant radiological health and safety impact, nor will it adversely affect any activities subject to regulation by the Nuclear Regulatory Commission.

Since we made no substantive comments, you need not send us the Final Environmental Impact Statement when issued.

Thank you for providing us with the opportunity to review this Draft Environmental Statement.

Sincerely,

Wm. H. Regan, Jr., Chief
Siting Analysis Branch
Division of Engineering

Letter #56

TENNESSEE VALLEY AUTHORITY
NORRIS, TENNESSEE 37828

JUN 18 1980

LATE LETTER

Environmental Manager
Bonneville Power Administrator
Post Office Box 3621 - SJ
Portland, Oregon 97208

Dear Sir:

This constitutes TVA's comments on the revised draft environmental impact statement entitled, "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System, Including Its Participation in a Hydro-Thermal Power Program," as requested in your April 2, 1980, transmittal letter. Following our review of the proposed action, as described, we have determined that TVA program interests will not be significantly impacted and therefore have no comments.

We appreciate the opportunity to review this draft statement.

Sincerely,

Mohamed T. El-Ashry, Ph.D.
Director of Environmental Quality

An Equal Opportunity Employer

Letter #57

IDAHO STATE HISTORICAL SOCIETY
610 NORTH JULIA DAVIS DRIVE BOISE, 83706

LATE LETTER

STATE MUSEUM

OFFICIAL FILE COPY

June 18, 1980

Department of Energy
Bonneville Power Administration
P. O. Box 3621
Portland, Oregon 97208

Dear Sir:

We recently received a copy of The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System E.I.S. and have the following comments:

1) The text on page IV-23 states that "many archaeological sites have been destroyed by reservoir fluctuations..." while the next sentence maintains that "inundation does not necessarily destroy archaeological sites." It is perhaps more accurate to say that although deeply submerged sites may be protected, reservoirs certainly will destroy others. This destruction is not necessarily limited to level fluctuations but can also result from normal wave action as deep as half the depth of the reservoir. It should also be noted that siltation presents a longer range accessibility problem than the reservoir itself, making accurate site location essential prior to inundation. Finally, since much of this information loss has already occurred, is there really a substantial impact from expansion of existing facilities? 1

2) No mention is made in the report of the impacts on archaeological resources by coal, nuclear or other thermal power plants. Such impacts would not be limited to specific plant sites but would include secondary and tertiary impacts at mining sites and disposal sites, including abnormal nuclear bombardment of datable materials. This is especially important in comparing thermal plants to hydro plants. 2

3) No comparison is drawn, with respect to archaeological resources, between the proposal and various alternatives in relation to the amounts of corridor construction and/or usage. Though many of these impacts seem obvious, they should be made explicit. 3

Department of Energy
June 18, 1980
Page 2

4) There should be a discussion of the impacts on archaeological and historical resources brought about by those options which increase or decrease federal involvement (e.g. encouragement of private development which is not necessarily subject to further federal measures for protecting archaeological resources). It could be noted how this might offset the harm of additional reservoirs. 4

I hope you will find these comments valuable in preparation of your final draft.

Sincerely,

Thomas J. Green

Thomas J. Green
State Archaeologist
State Historic Preservation Office

Letter #58

STATE OF UTAH
Scott M. Matheson
Governor
Kent Briggs
State Planning Coordinator

Division of Policy and Planning Coordination
Intergovernmental Relations Section
Lorayne Tempest, Associate State Planning Coordinator
124 State Capitol
Salt Lake City, Utah 84111
533-4981

A-95
State Clearinghouse
533-4976
533-4971

Environmental
Coordinating
Committee
533-5794

Human Resources
Coordinating
Committee
533-4981

A-85
Federal/State
Coordination
533-6083

Federal Resource
Information
Center
533-4983

LATE LETTER

June 20, 1980

Environmental Manager
Bonneville Power Administration
P.O. Box 3621 - SJ
Portland, Oregon 97208

SUBJECT: Revised Draft, EIS/ The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System. (SAI #800407038)

Dear Sir:

The Utah State Environmental Coordinating Committee has reviewed the information in the Revised Draft EIS, The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System, including its participation in a Hydro-Thermal Power Program. The Committee has identified at this time no discrepancy with existing state plans and objectives.

Thank you for the opportunity to review and comment on this material.

Sincerely,

Lee M. Allen
A-95 Coordinator

LMA:ba

Letter #59 (Official copy)

UNITED STATES DEPARTMENT OF COMMERCE
The Assistant Secretary for Productivity, Technology, and Innovation
Washington, D.C. 20230
(202) 377-4335

June 25, 1980

LATE LETTER

Environmental Manager
Bonneville Power Administration
Department of Energy
P.O. Box 3621 - SJ
Portland, Oregon 97208

Dear Sir:

The Department of Commerce reviewed the draft environmental impact statement by the Department of Energy relative to "The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System." and forwarded comments to you in our letter of June 12, 1980.

Since that time, additional information has developed which is pertinent to the project. This additional information from the National Oceanic and Atmospheric Administration is enclosed for your consideration.

We are pleased to have been offered the opportunity to review this statement.

Sincerely,

Robert B. Barrett for

Bruce R. Barrett
Acting Director, Office
of Environmental Affairs

Enclosure Memo from: Dale R. Evans
National Marine Fisheries Service
National Oceanic and Atmospheric Administration

Letter #59 (continued)

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
Environmental & Technical Services Division
P. O. Box 4332, Portland, Oregon 97208

Rec'd PP/EC
JUN 24 1980

June 12, 1980

F/NWR5:SHS

LATE LETTER

TO : PP/EC - Joyce M. Wood

FROM : F/NWR5 - Dale R. Evans Dale R Evans

SUBJECT: Comments on Revised Draft Environmental Impact Statement -- The Role of the Bonneville Power Administration In the Pacific Northwest Power Supply System (DOE, BPA) DEIS #8004.05

The draft environmental impact statement for The Role of the Bonneville Power Administration In the Pacific Northwest Power Supply System that accompanied your memorandum of April 7, 1980, has been received by the National Marine Fisheries Service for review and comment.

The statement has been reviewed and the following comments are offered for your consideration.

General Comments:

The National Marine Fisheries Service (NMFS) is providing its comments on the revised DEIS based on its legal jurisdiction and expertise with regard to living marine resources under the National Environmental Policy Act (NEPA), the Fish and Wildlife Coordination Act (FWCA), the Anadromous Fish Conservation Act, and other authorities. In particular, NMFS' comments on the DEIS reflect its responsibility and concern for the protection, mitigation, and enhancement of anadromous fish stocks (salmon and steelhead) and their habitat.

Our reading of the draft EIS indicates that the alternatives presented represent a greater or lesser BPA role in the regional power system, and a greater or lesser implementation of the "one utility concept" for the Pacific Northwest. Under the Council of Environmental Quality (CEQ) regulations, the analysis of alternatives is deemed to be the "heart" of the EIS (§1502.14); it must consider those alternatives in detail "so that reviewers may evaluate their comparative merits;" provide a basis for "defining the issues, and providing a clear basis for choice;" and include appropriate mitigation measures.

The alternatives analysis in the BPA Role DEIS falls short of these goals. The level of analysis presented is of such a general and vague nature that comment becomes difficult -- to comment effectively would require the writing of a substitute analysis. More precisely, there is little indication of the programs BPA would carry out under each alternative, e.g., the extent of load management and peaking modifications which BPA contemplates under each alternative. Without such detail, comparative merits and environmental impacts are difficult if not impossible to assess, and issues cannot be sufficiently defined to provide an informed basis for selection among the alternatives.

2

This inadequacy in the detail of alternative analyses necessarily transfers to the evaluation of environmental consequences. With respect to anadromous fish and their habitat, impacts of existing and future operations of the power system are discussed in only the most general terms and in a conclusory rather than an exploratory manner. The comparative impacts to fisheries in the range of alternatives simply cannot be assessed on this basis. Thus, it is difficult to see how the BPA Role DEIS satisfies §1502.16 of the CEQ regulations, which require "an analytic basis" for environmental impact comparisons, including an assessment of direct and indirect effects. Other aspects of environmental analysis required by the CEQ regulations [§1502.16(a) - (e)] are also unaddressed -- e.g., "possible conflicts between the proposed action and the objectives of Federal, regional, State, local...Indian depletable resource requirements" relative to anadromous fisheries; and mitigation measures available to protect anadromous fisheries.

As for the data used in the BPA Role DEIS, little documentation or scientific support is provided. With respect to anadromous fisheries this lack of documentation and quantitative analysis cannot be attributed to a corresponding lack of data. On the contrary there is much research data available on the impact of hydroelectric projects on these fish and their habitat, as well as mitigation measures which address or alleviate these impacts. NMFS would be able to provide an overview of this research upon request, in order to satisfy the CEQ regulations requirement that the scientific integrity of the EIS analyses be assured and documented (§1502.24). Where quantitative or other research data are not available, a "worst case" analysis should be used, with an indication of probability or improbability (§1502.22). In the case of anadromous fish, detrimental power operations and destruction of already limited habitat might well result in the extinction of historical runs. Indeed, this may have already occurred to certain upriver stocks, and most of the remaining upriver stocks show serious declines in population levels.

Finally, we believe that the DEIS as drafted discourages meaningful public and agency comment. Although the subject matter presented in the DEIS is extremely complex and esoteric, it appears that little attempt was made in the preparation of the DEIS to accommodate the lay audience. For example, there is no glossary, no explanation of concepts, agreements and organizations to assist the reader; there are referrals to other documents from which the basis of several assumptions and scenarios are formulated without explanation. These inadequacies can only intimidate the reader and result in superficial or incomplete review by affected interest groups and agencies.

Specific Comments:

Page I-6 to 9. The statement of BPA Mission and Goals and Guideline Principles should include recognition of the Administrator's obligation to give preservation and enhancement of fish and wildlife equal consideration with power purposes. This is mandated under the FWCA.

Page I-10. Generally, we support the "one utility concept," if the concept is interpreted so that the benefits and flexibility of operating as one utility inure to the benefit of fisheries production as well as power production. This has not been the case to date -- fisheries have not been adequately incorporated into planning and operational decisions on more than an *ad hoc*, short term basis.

Page I-19 to 20. The discussion of "other Environmental Analyses" does not clarify the relationship of the DEIS to other EIS's which might be prepared, particularly since this DEIS does not actually represent a proposed "program." The statement should discuss whether BPA will prepare a more detailed programmatic EIS on the selection of its program, -- describing e.g., what conservation measures are proposed, including peakload management, the related fishery benefits, and impacts of various alternative measures which would comprise the BPA program.

The DEIS should state whether a new NEPA document would be prepared if the proposed northwest power bill becomes law. At least with respect to anadromous fisheries, which would have increased standing in power planning under the bill, it appears that a supplemental EIS would be required.

Page I-28, last paragraph. With respect to transmission line services and planning and the one-utility concept, BPA should use these authorities and approaches to encourage and smooth the implementation of fishery improvement measures. This is in keeping with the "equal consideration" requirements of the FWCA.

Page I-29, first paragraph. With respect to power planning, anadromous fishery requirements must also be considered as an underlying and "given" planning assumption. This is in keeping with the "equal consideration" requirements of the FWCA.

Page I-34. As noted in our General Comments, the "Ranking Alternative" does not actually represent a program. There is no clear indication of the actions BPA would propose to take under each of the areas identified to a degree necessary for accurate assessment and comparison of environmental impacts. All alternatives must include consideration of fishery impacts in both power planning and operation in view of the FWCA.

Page I-38. As noted in our General Comments, a "worst case" analysis of the impacts of hydroelectric dam operations on anadromous fish would reflect the ultimate extinction of certain upriver stocks.

Page II-4, section D. The residential and industrial use patterns noted here underscore the availability of load management alternatives and improved energy efficiency as a means of meeting demand. In turn, such measures could minimize adverse impacts to anadromous fisheries.

Page III-5, paragraph 2. We disagree with the characterization of the BPA role as "institutional." Certainly BPA has sizable influence in the substantive areas of energy direction for the Northwest as a whole, through its use of statutory authorities. How BPA uses its influence (and to what ends) affects environmental impacts to a great extent. This is clearly evident from a reading of northwest power bill proposals and further discussions in the DEIS.

Page III-8, paragraph B.1.b. The second paragraph on "Customer Services" indicates that they are conditioned on environmental restraints. The DEIS should discuss how and to what extent these services are conditioned, particularly with regard to fisheries. We are particularly concerned about how fishery-related restraints would be incorporated into load factoring and forced outage reserves (Page III-9). The "one-utility concept" should allow the incorporation of fishery concerns into these and other areas, with greater flexibility than is presently utilized.

Page III-13, paragraph d.(1). Fishery-related concerns should be reflected in all aspects of power planning. With respect to load forecasting, the data base used should include fish protection requirements.

Page III-14, paragraph d.(2). The second paragraph of "Power Planning Document" indicates the availability of some public involvement and input, and could be read to include fishery agency input to the extent "available and appropriate." We suggest that the DEIS describe public and fishery agency involvement more specifically here, and that this involvement be fully provided for at all critical stages of document preparation.

Page III-15, paragraph d.(4). Utilization of "current planning assumptions" will not satisfy BPA obligations under the Fish and Wildlife Coordination Act. Current planning assumptions must be revised to include "equal consideration" of fish and wildlife requirements. Only in this manner can we avoid the present ad hoc approach to fish protection, with its resulting problems for both fishery and power production.

Page III-17, paragraph e.(2). BPA should note that the FWCA provides some authority for conservation efforts, to the extent that these efforts assist in the equal treatment of fish and wildlife with other project purposes.

Page III-18, paragraph e.(3). The analysis of conservation requires more specificity. As now drafted, the 14-point BPA policy is so general that it could support a wide range of measures, including conflicting measures. The DEIS should state the kinds of "energy conservation programs" BPA would propose or encourage under its "policy." We assume that conservation includes load management directed at reducing peak power demand, through pricing or other means: this should be referenced throughout the discussions of "policies," particularly the discussion of pricing (Page III-21) and customers (Page III-19).

Page III-53 to 62. The statement should discuss the extent this alternative is available under existing authority. (Several aspects of the alternative seem available to BPA if a less restrictive view of its authority were taken.)

Page IV-10, paragraph b. The increased use of hydroelectric projects for peaking, with increased river fluctuations, is never correlated with the fishery impacts noted below.

Page IV-13. Paragraphs (b) and (c) are confusing; they indicate that there "may or may not" be certain efforts or impacts. For example, paragraph (b) notes that peak pricing may reduce peak demand, but does not indicate whether this approach will be implemented or even encouraged. Similarly, paragraph (c) does not indicate whether fluctuations will, in fact, be likely.

Page IV-13. The discussion of coordination arrangements should indicate that it might be desirable to modify existing operating agreements in furtherance of the "one-utility concept."

Page IV-15, paragraph 2. The Columbia River anadromous fish runs are presently in a severely depressed condition due mainly to the impact of hydroelectric development. The economic value and importance of the corresponding sport and commercial fisheries are therefore also depressed. Based on a recent 3-year

average of sport and commercial harvest, and 1977 prices, the Columbia River salmon and steelhead fisheries are valued in excess of $132 million annually. The potential value of these fisheries with mitigation implemented for the effects of hydroelectric development would be much greater. Besides the direct economic benefits of salmon and steelhead, ecological and social values to residents of the Pacific Northwest are also attributable to the anadromous fish runs (see also the Water Resources Council's "Principles and Standards"). The DEIS should be corrected to reflect these data.

Page IV-15, paragraph 3. The paragraph implies that the resident fish resource provides recreational opportunity for sport fishermen while the anadromous fish resource supplies a commercial fishery. About one-third of the salmon and steelhead harvest from Columbia River stocks is by sportsmen and the resulting sport economic value far exceeds the commercial fishery value.

Page IV-15, paragraph 4. The development of hydroelectric projects in the Columbia Basin is the major factor related to the decline and continued depressed state of the anadromous fish resources.

Page IV-16, paragraph 1. The DEIS should reflect that while many factors have combined to cause the decline of salmon and steelhead populations, hydroelectric development has had a greater, lasting adverse impact than all of the other factors combined.

Page IV-16, paragraph 2. All upriver stocks of salmon and steelhead are presently under review for possible action under the Endangered Species Act of 1973.

The State and Federal fishery agencies have historically been relatively successful in coordinating research and management amongst themselves. However, coordination between the fishery agencies and those agencies developing and controlling the Columbia River for other uses has been sorely inadequate and has consequently resulted in severe fishery losses.

Page IV-16, paragraph 5. The DEIS does not present the extent of fishery losses caused by the combination of low flows and hydroelectric projects, including long-term cumulative impacts. For example, during 1973 and 1977, two recent low flow years, over 95 percent of the outmigrating salmon and steelhead population was lost. These data should be reflected in the DEIS.

Page IV-17, paragraph 1. Data collected from salmon spawning grounds in the Snake River Basin have shown that the adult delays, stresses, and injury resulting from passage over the dams has resulted in greatly reduced spawning success for those fish that do survive the upstream migration.

Page IV-17, paragraph 2. The DEIS should indicate that flow control and fluctuations caused by hydroelectric generation have repeatedly resulted in extensive losses of emerging fry in the Snake and mid-Columbia Rivers.

Page IV-17, paragraph 3. As noted in our General Comments, the discussion of mitigation and compensation measures must be substantially expanded to satisfy the requirements of the CEQ regulations. The actions BPA will implement or encourage for fisheries protection and the relative merits of these actions, including comparative benefits to fisheries, must be thoroughly discussed.

The DEIS portrays an overly optimistic view of coordination and cooperative efforts aimed at preserving and enhancing Columbia River salmon and steelhead. Coordination will not restore the fish runs so long as insufficient consideration and status are given to the requirements of salmon and steelhead by agencies controlling the operations and improvements of the hydroelectric projects. Current consideration of fishery requirements is subject to the generation of near maximum levels of power and future plans to operate the Columbia River for maximum energy production. We believe coordination will become a truly useful tool to maintain and restore fish runs only after legislative mandates require the river to be operated for multiple purposes, including fisheries.

Page IV-17, paragraph 4. The DEIS should clearly indicate that the effectiveness of turbine bypass systems and smolt transportation have yet to be determined. With turbines screened and some bypass spill provided at several dams, juvenile chinook have still sustained losses of 15 and 21 percent per project in 1978 and 1979 respectively.

Page IV-35, paragraph c.(2). This paragraph should describe the degree and extent of possible flow fluctuation control.

Page IV-35, paragraph d. There are various ways of "running the river" using a coordinated approach. These should be set out and discussed, so that relative benefits and other comparisons may be made.

Page IV-93, section B.1. The draft statement should discuss how "regional cooperation and coordination" would be implemented and how conflicts between power and non-power interests would be resolved. Are changes in decision-making processes anticipated for improved accommodation of environmental and other concerns? The discussion here and elsewhere fails to recognize these and related complexities affecting power system development.

The second paragraph of this section indicates that non-power concerns have historically been accommodated with little conflict. With respect to anadromous fisheries, this is certainly inaccurate -- the conflict between fish and power production has been long-standing, and the cumulative adverse effects on fish populations and habitat have been dramatic.

Page IV-94, paragraph a. This discussion seems to be the major thrust of the DEIS, yet it is dealt with only superficially. The DEIS should state the various modes or alternatives for regional cooperation and coordination which BPA is considering. The relative environmental and ecological impacts of these alternatives, including the failure to coordinate, must be thoroughly analyzed.

Page IV-97 to 98, paragraph (5). The opportunities provided for input from fishery and other non-power interests should be mentioned. The DEIS should expose how these opportunities will be translated into actual decisions which are responsive to non-power concerns. It is clear from past experience that input alone is insufficient.

For example, with respect to fisheries, power-related impacts are generally known and understood by power interests but are simply not accommodated in power decisions to the extent necessary. The reliance placed on "concensus" seems overly optimistic in light of this experience.

Page IV-100, first paragraph. In view of the mandate of the FWCA, NMFS objects to the implication that power interests and demands will be found controlling in fishery-power conflicts. Severe adverse impacts on fisheries would definitely result and, using a "worst case" analysis, could lead to extinction of some stocks. We suggest that this section explore in some detail the methods which are available to minimize fishery impacts while accommodating and/or shaping power demand, and identify those methods which BPA will adopt or encourage.

Page IV-101, paragraph c. Our comments above are equally applicable to this section.

Page IV-110, section (2). The discussion of load management is too general to support informed decision-making based on the DEIS. In particular, the references to direct load control, peak pricing, and energy storage do not fully explore the range of available alternatives.

The costs of load management may be expensive when viewed in isolation, but they must be viewed in the appropriate context. These costs can only be assessed in comparison with costs of new peak power generation, as well as environmental costs which will be felt without load management (e.g., the value of fishery losses due to peaking fluctuations at hydroelectric projects).

The DEIS should comment on what forms of load management BPA will adopt or encourage, and their relative environmental impacts. The discussion in Pages IV-112 to 113 does not adequately address these concerns. Without load management, for example, a "worst case" analysis of fishery impacts might indicate that upriver stocks would no longer survive.

Page IV-119, paragraph b.(1). The DEIS should review the actual hydroelectric capability of the region when economic, environmental and political constraints are considered.

Page IV-120. The environmental impacts of hydroelectric operations on fisheries are inadequately explored. The cumulative impacts of existing dams should be discussed quantitatively, in terms of lost or impaired fish populations. Of course, the remaining fish habitat which would be adversely affected by new hydroelectric projects would reflect an even greater relative loss in view of these cumulative impacts, since remaining habitat is more critical and valuable due to its scarcity.

Citations of supporting documentation should be provided throughout.

Page IV-123. Again, the discussion of fishery impacts is simplistic and cannot provide a basis for comparative analysis. The last paragraph, referencing lower mortalities through bulb turbines, is questionable based on present data. No studies to date indicate that bulb turbine mortalities are statistically different from those associated with conventional turbines.

Page IV-187. Inherent in all five resource scenarios is the fact that hydropower will play an important tole. Since there is no mention of external factors impacting present hydro operations, it must be assumed that all water sources will be optimized for power production. We do not perceive any accommodations for fish flows which, when translated for use in this document, will mean loss of megawatts.

The omission of this type of data makes all of these scenarios unrealistic and therefore they cannot present a reasonable estimate of the environmental impacts and available mitigation measures.

Page IV-191, paragraph 3. The "worst case" scenarios all seem to meet the projected West Group Forecast load predictions. Historically, the West Group Forecast has been conservative in that it has projected a higher load than that which actually materialized. By comparison, a "worst case" scenario for fish (other than extinction) would occur when all hydro resources are run strictly for peaking purposes, recognizing that certain navigation and flood control criteria must be met. It is important that this type of "worst case" fisheries scenario also be demonstrated and analyzed.

Page IV-192, paragraph 1. As discussed above, a "worst case" scenario for fish resources was not demonstrated in the DEIS. In this paragraph of the DEIS such a scenario is ruled out because it is not "worst case". This approach is not only unrealistic, but also inadequate for review purposes. We suggest that, along with the "worst case" fish scenario, the discussion include a "best guess" future resource scenario. If it is thought that a certain mix of resources will develop and will result in quantifiable impacts, the "worst case" scenario presented in the DEIS is virtually meaningless because as stated in the DEIS, the resources will never develop in this manner.

Page IV-192, paragraph 3 through Page IV-193, paragraph 3. A recent GAO report "Review of Peaking Power Needs in the Pacific Northwest (EMD-80-46) cast substantial doubt on the Pacific Northwest Utilities Conference Committee's (PNUCC) 1979-99 forecast. Specifically, the report stated that the PNUCC forecast does not balance a forecasted peak load with the forecasted available resources and if they were, PNUCC's forecast peak could be reduced by over 2,000 MW. This in turn would reduce the peak power deficits forecasted by PNUCC through 1989.

The GAO report also stated that the reserves for contingencies may be too conservative. Quoting directly, it states:

"Three factors contribute to this conclusion. First, loss-of-load calculations are based on the probability of no more than one expected outage in 20 years. Most utilities in other regions require a reliability of no more than one expected outage in 10 years -- a level which may still be too high, according to a recent report by the Congressional Research Service. Second, the region's planned reliability appears to have been even greater than this once-in-20-years probability, because of the conservative "rolling" criterion used for estimating system reserve requirements. Finally, over 1,000 MW of power sold by BPA to its direct service industrial customers can be interrupted at any time for any reason, and could be used as system reserves to help meet peaking needs. This reserve, however, has not been taken into account in determining the region's peaking surplus or deficit."

Finally, the GAO reported that "...although PNUCC has been reducing its projected rate of increase for peak loads, actual peak loads in the region reportedly averaged nearly eight percent below forecasted peak loads during the period 1973 to 1977."

Since this GAO report casts doubt on the PNUCC forecast, we feel that a review of the assumptions should be made and explanations provided. Even though the PNUCC forecast may present an inflated "worst case" it appears to be inaccurate and therefore of no help in trying to determine the true impacts.

Page IV-193, paragraph 1. The conservation induced load reduction of 448 MW requires more explanation. It appears this is included to further reduce an over- estimated PNUCC load forecast. Why the PNUCC did not include this reduction in their original estimates rather than as an add-on by BPA should be explained.

Page IV-193, paragraph 2. NMFS believes that more consideration should be given to peaking alternatives such as combustion turbines. This consideration is particularly important because of potential adverse impacts to fish caused by river fluctuations. There is no mention in this DEIS of the possibility of coal gasification or liquification as fuel sources for peaking units.

Page IV-193, paragraph 3. One of the prime factors, if not the prime factor, for decreasing the demand for power is the cost of fuel. To omit the influence of resource costs on energy demand is again unrealistic. Surely there is some trend information which can be correlated to show as resource prices go up there is an associated quantity or rate of conservation.

Page IV-193, through IV-229. Scenario A (100% Renewable Generation) adds over 15,000 MW of hydro generation or over two-thirds of the total new resources to meet the PNUCC load. However, the impacts summary shows no aquatic impact, only land use effects. Any discussion of impacts must reflect the potential impact on fish.

Scenario B shows a conservation "production" of over 10,500 MW, almost 50 percent of the projected PNUCC load. The explanation of how this was achieved is not comprehensible as written in Table IV-34 on Page IV-199. This is an important item and should be presented in a manner understandable to all readers. Additionally, there is an increase of over 7,000 MW of hydro capacity projected here with no discussion of impacts.

Scenarios C, D, & E also have hydro additions with no aquatic impact analysis. This does not reflect the potential environmental impacts of future generation, or BPA's ability to affect the regional resource mix under the one utility concept.

The consumptive water use of the five different scenarios is an important factor which received little attention and discussion. Scenario D (100% nuclear) has the largest amount of increase. Under "D" consumptive water use triples over the present operation. Scenario C (100% coal) shows only a 60 percent increase. The associated impact of this consumptive water use is not discussed. The discussions associated with these scenarios should indicate the effect of the consumptive use on streams and their fishery resources.

Page IV-230, second paragraph. With respect to fisheries, we cannot agree that existing depleted conditions are the baseline against which additional impacts should be measured. Use of this baseline would institutionalize and constitute acceptance of existing operational problems in the power system, which NMFS and other fishery agencies are presently seeking to improve. A better "baseline" would be optimum production levels of both fisheries and power.

Page IV-231, second paragraph. We question the statement indicating that if the PNUCC forecast is in error, then environmental impacts will be less severe. In fact, if new and increased generation capability is tied to the PNUCC forecast, many adverse environmental impacts will not be avoided even if demand falls below forecast levels. A more realistic approach would be to develop an accurate forecast of demand which incorporates strong conservation and load management programs, and which will help to minimize adverse environmental impacts through proper planning.

Page IV-235, paragraph (2), and Page IV 243, paragraph (3). As noted here, BPA has substantial ability to influence the energy development patterns for the Northwest. How BPA will use this influence to minimize adverse environmental impacts associated with energy development is pertinent to the DEIS. The steps BPA could take in this regard, and their relative environmental impacts should be thoroughly explored.

Page IV-260 to 261, paragraph (2). The DEIS should discuss the kinds of peakload management BPA will propose (if any). The environmental and ecological impacts which can be expected with various levels of peakload management, or if no such management is instituted, needs to be explained.

Page IV-263, paragraph (5)(a). This section gives no clear indication of what BPA proposes to undertake. For example, in the second paragraph, there is no way to assess whether or not BPA intends to initiate peakload management.

The use of vague terms and conclusory statements in this and the following sections obscures the distinction between the proposal and the alternatives. Theoretically, it seems that BPA could put together almost any program and consider it to fall under any one of the alternative "roles" described in the DEIS.

Page IV-274 to 277. Please refer to our comments for Pages IV-17, and IV-93 to 101 regarding fishery-power conflicts.

Page IV-313 to 330. Our comments throughout would apply to the appropriate conclusions in this Summary Section. Additionally, it is worth noting that litigation is almost certain if fishery interests are not reflected in power planning and operations. A coordinated regional power system which does not provide for improved accommodation of fishery interests will not decrease the likelihood of such litigation.

We appreciated the opportunity to provide our comments. Because our comments raise such significant question on the adequacy of the DEIS, we believe that it must be revised and subject to further review. We would be pleased to provide pertinent fisheries data upon request.

CLEARANCE: SIGNATURE AND DATE:

F/HP:JWRote Yates M. Barker, Jr. for JWRote 6-23-80

cc: F/NWR

Letter #60

Lane Council of Governments

L-COG Referral #	0E68
State PNRS #	
Type of Referral	A-95

REGIONAL CLEARINGHOUSE REVIEW AND COMMENT CONCLUSIONS

Telephone: 687-4283

Applicant Bonneville Power Admin. By: Guy Justice, Clearinghouse Coordinator

Project Title: Environmental Impact Statement: Role of BPA in Pacific N. W. Power Supply System; Hydro-thermal program. Date: 6-27-80

___ PNRS SUMMARY ___ FORMAL APPLICATION x OTHER LATE LETTER

The L-COG Regional Clearinghouse has reviewed the proposed project for its relationship to existing plans, goals, or policies of this agency and finds the proposal to be:

- [ ] It is consistent with or contributes to areawide planning.
- [ ] Consistent, pending resolution of concerns noted in comments included.
- [ ] It is inconsistent with areawide planning.
- [ ] Request the opportunity to review the full application.
- [ ] No comment.
- [ ] Professional comments are included.

For A-95 Reviews Only:

- [xx] Recommend approval.
- [ ] Do not recommend approval.
- [ ] Recommend approval, conditional on resolution of concerns included.
- [ ] No comment.

For Environmental Assessment (if attached):

- [ ] Negative declaration is consistent with information presented.
- [ ] Environmental assessment is adequate.
- [ ] Environmental assessment is not adequate for the following reasons.
- [ ] Impacts exceed established environmental standards referenced.

L-COG REVIEW COMMENTS

Note: L-COG has received review comments from the following local agencies which have been incorporated into this summary: Eugene Water & Electric Board

A-95 review comments should not be considered as a substitute of required permit or license procedures necessary for projects or programs. Nor does this review system waive regularly required performances standard reviews.

Copy to:

Attachment B

RESPONSES TO COMMENTS RECEIVED ON REVISED DRAFT ROLE ENVIRONMENTAL IMPACT STATEMENT

LETTER NO. 1

Caroline Imports, Exports

No response required.

LETTER NO. 2

Mr. Donald B. Slaughter

Letter No. 2, Comment No. 1

Individual utilities are responsible for the power needs of their own customers and plan accordingly. As members of PNUCC, these utilities and BPA work together in developing regional plans for system expansion to serve regional needs. BPA and other Pacific Northwest utilities are also members of the Pacific Northwest Power Pool which are in turn an integral part of the Western System Coordinating Council, one of nine such groups which form the National Electric Realiability Council.

Through membership in these organizations we are made aware of the power needs and resource availability in other parts of the country and can appraise the impact on the Pacific Northwest. Also, available for informational purposes are reports such as DOE's National Grid Study and the Corps of Engineers' National Hydropower Study.

Letter No. 2, Comment No. 2

The Goodnoe Hills wind facility, is a BPA "pilot" project, currently under construction near Goldendale, Washington. Figure IV-1 has been revised to include this resource.

Letter No. 2, Comment No. 3

The potential of large-scale wind generation was already addressed on page IV-133 of the RDEIS and is included in the FEIS.

Letter No. 2, Comment No. 4

You are correct in stating that Washington may have considerable unidentified geothermal potential. The text has been changed to indicate, based on USGS electrical energy estimates of known resources, that Washington presently has no identfied resources capable of generating electricity in the near term.

Letter No. 2, Comment No. 5

Recent estimates of domestic uranium producible at $30 or less per pound U308 are about 700,000 tons and growing at about 5 percent a year in spite of production ("Uranium Resources Production and Demand" OECD/-IAEA, December 1979). Figuring about 200 tons U308 per reactor per year, the 100 or so reactors operating or under construction should have sufficient uranium available for their 35 year financial lifetime. Prices are fixed by the market place, but uranium is so widely available (it is even available from the ocean), the fuel cost is such a small portion of the cost of electricity, and the fuel "pipeline" so long (at about 3 years), that the possibility of a cartel being able to fix and hold a price high enough to make nuclear power noncompetitive is extremely remote.

Letter No. 2, Comment No. 6

Catastrophic accidents are not considered for any of the power sources. Each type of electric power source has the possibility that a facility might be rendered inoperable for the remainder of its financial lifetime by either man or nature.

Letter No. 2, Comment No. 7

An entity purchasing power from the owner of a power resource may do so in two basic manners. First, if the resources is already in existence and a certain amount of power appears to be surplus to the needs of the owner for some period of time, the purchasing entity may simply buy that amount of power. This type of purchase is common in cases of temporary surpluses and deficits among interconnected power suppliers, and generally involves only short term purchases and sales.

A second type of purchase arrangement is used when the power resource in question is not yet constructed. The owner planning to build such a resource may offer to sell the ownership share in the project or, alternatively, a share of the resource's planned capability. In either event, the purchaser is obligated to pay its percentage of the project's construction and operating costs and is allowed to exercise ownership operating rights for its share, just as if the purchaser were a part owner. This type of arrangement is customary throughout the United States.

Whether purchase of output or purchase of capability is desirable in a given instance is dependent upon such considerations as the size of the resource to be constructed, the experimental or proven nature of the technology involved, the size of the purchasing utility, and the transmission capability of the utilities involved. Since the purchase of resource capability carries with it the risks of unexpected cost overruns and operating problems, it might appear that these arrangements are imprudent, even though they are traditional throughout the American utility industry. The problem is, that in the absence of a purchase of capability, only very large utility systems could undertake the construction of a generating resource and thus assume the risk that such a resource, contructed at least in part to meet the loads on another utility system, would perform less well than expected. The constructing entity would need to see such output at a premium to reflect the risk it assumed.

In addition, a generating corporation, formed to construct such resources, would be unable to sell securities to finance these resources during their period of construction because it would have no revenues to assure investors the eventual repayment of their capital contributions. In the absence of a purchaser's guarantee to pay the cost of a resource, whether or not it is constructed, operating, or operable, such a generating corporation would be unable to fulfill its purpose.

The purchase of capability reduces cost to consumers by reducing financing costs of the new resource, whether that resource is conservation or a generating facility. Financing cost (a very substantial portion of total power costs) is reduced because bond buyers are willing to accept lower interest rates on bonds that are more secure; the wider the risk can be spread, the more secure the bonds. Also, the purchase of capability of resource spreads the risks and benefits of the resource in an equitable manner, in that those utilities and their consumers who will receive the power benefits will equally share the costs and risks of resource construction.

Therefore, assuming the proper construction oversight and controls are available to the purchasing entity, guaranteeing purchases of power generating resources is often the most economical means by which such power supply could be acquired to meet a utility's loads.

Letter No. 2, Comment No. 8

The numbers are from, "Technology, Safety and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station" NUREG/CR-0130, done by Battelle Pacific Northwest Laboratory. This is the most complete and directly applicable source to the Trojan powerplant available at this time in the Northwest.

Letter No. 2, Comment No. 9

Fusion was not discussed in detail because it does not appear to be available within the scope of this document. No nuclear reactor, fusion or fission, today or planned, releases any measurable neutron radiation into its neighborhood (neighborhood is understood to mean at least outside the reactor containment). A pure fusion reactor does not produce any materials useful in the construction of a hydrogen bomb that are not available from other sources, and thus would not make a bomb maker's task any easier.

Letter No. 2, Comment No. 10

The probability of solar power satellites making a contribution to the energy supply in the Pacific Northwest before the year 2000 is extremely small. The inclusion of solar power satellites in this discussion would not be consistent with those renewable resources already selected for discussion.

Letter No. 2, Comment No. 11

The reference to page IV-102 is a discussion of conservation as a technology, it is not a discussion of implementation strategies. The conservation measures referred to here would be implemented under voluntary, incentive, or mandatory programs.

With regard to the reference to page IV-193, there is no question that the price and availability of fossil fuels for transportation and space heating, for example, will have a substantial effect on the demand for electricity over the next 20 years. However, this does not invalidate the renewable resource and conservation scenarios, which were selected to demonstrate the technical potential and impact for these resources including the resultant displacement of central station generation. To the extent that the demand for electricity increases more rapidly than currently forecast, both utility resource requirements and other options will be altered. As electricity prices increase, the cost-effectiveness of renewables and conservation would also increase, thereby increasing their cost-effective potential. Any residual demand would have to be made up by new generation. As far as the scenarios are concerned, however, the simplifying assumption was that the effect of resource costs on energy demand would affect the scenarios equally with respect to the price of electricity.

Letter No. 2, Comment No. 12

The method of storing electrical energy in the Pacific Northwest (PNW) is in the form of water in reservoirs on rivers. Electrical energy from another source can be stored by reducing the generation at a hydroelectric plant and storing the water which would have been used. This procedure will be used until the storage capacity and hydrogeneration capability have been committed. With this storage system available, no other storage has been considered except pumped storage, which is a hydroelectric concept. Regional pumped storage surveys have been done by the U.S. Corps of Engineers, and certain utilities have made preliminary investigations of certain sites. However, none are under active consideration at this time.

The investigative work on other electrical energy storage systems is being supported by PNW electrical utilities, including BPA, through contributions to the Electrical Power Research Institute (EPRI). EPRI is a national nonprofit research and development institute supported by contributions from all electric utilities. All their research is done for the benefit of electric utilities, and this includes energy storage methods.

All current storage systems produce less energy than they receive. These losses can be one-third, or even more. The present PNW hydro storage system is an exception, being 90 to 100 percent efficient.

LETTER NO. 3

Washington State Parks and Recreation

No response required.

LETTER NO. 4

Crosby Library, Gonzaga University

No response required.

LETTER NO. 5

Advisory Council on Historic Preservation

No response required.

LETTER NO. 6

Montana Historical Society

No response required.

LETTER NO. 7

University of Washington, Institute for Environmental Studies

Letter No. 7, Comment No. 1

Revisions to the text have been made to accommodate the comment.

Letter No. 7, Comment No. 2

Revisions to the text have been made to accommodate the comment.

Letter No. 7, Comment No. 3

We agree and certainly have an appreciation for the problem. The rapidly changing circumstances with regard to regional legislation, for example, was one of the main reasons for Bonneville issuing a Revised Draft EIS (RDEIS).

Basically, what you are advocating is a "tiering" concept. The advantages and opportunities for following this approach, which is encouraged by CEQ, were discussed in the RDEIS on page I-19.

LETTER NO. 8

Oregon State Executive Department

Letter No. 8, Comment No. 1

Revisions to the text have been made to accommodate the comment.

Letter No. 8, Comment No. 2

The question of erosion at existing projects had been addressed in the RDEIS on pages IV-18 and IV-23. The question of erosion at future projects was addressed on page IV-120 under Environmental Impacts.

Letter No. 8, Comment No. 3

In accordance with the Intergovernmental Cooperation Act of 1978, OMB Circular No. A-95, Executive Order 11514, and the CEQ Regultions for implementing NEPA, BPA is obligated by law to coordinate major Federal actions with all affected levels of Government. BPA has developed and implemented environmental procedures to insure full compliance with State and local plans and programs. The issues discussed in the Role EIS are consistent with these procedures.

LETTER NO. 9

Homberg Farms Inc.

No response required.

LETTER NO. 10

F. H. Stoltze Land and Lumber Company

No response required.

LETTER NO. 11

Mr. W. G. Nibler

No response required.

LETTER NO. 12

Butler Associates, Inc./Williams Brothers Engineering Company

No response required.

LETTER NO. 13

Lane Council of Governments

No response required.

LETTER NO. 14

State of Idaho; Division of Budget,
Policy Planning and Coordination

No response required.

LETTER NO. 15

D. E. Zimmerman

No response required.

LETTER NO. 16

Enerjoules Limited

Letter No. 16, Comment No. 1

Impacts on the ultimate consumer are considered in the Role EIS. However, the primary purpose of this EIS is to assess impacts of the proposed action and alternatives on the physical environment, not socioeconomic impacts at the retail level.

One of the alternatives considered in the EIS (Alternative 4) incorporates some of the basic principles of the legislation introduced by Representative James Weaver of Oregon in November 1977 in the 96th Congress. Under this alternative, Bonneville power would be marketed under two rates: (1) a lower rate, based on lowest production costs, for use by domestic and rural customers, city, county, and State government and public-transportation, and (2) a second rate, based on costs of all energy in the pool in excess of that marketed under the first rate, for use in meeting the consumer demand not served under the lower rate.

Bonneville considered two different approaches to baseline or two-tier rates in its 1979 wholesale rate filing. One of these approaches was similar to that included under Alternative 4. The other involved a two-tier hydro/thermal rate. Bonneville's General Counsel indicated that Bonneville currently lacks authority to implement rate schedules that contain separate rates for thermal versus hydro generated power. The net-billing agreements established with the approval of Congress, authorized Bonneville to market power for thermal plants owned and constructed by non-Federal interest and to meld the cost of the thermal power into its power rates.

LETTER NO. 17

State of Oregon; Department of Environmental Quality

Letter No. 17, Comment No. 1

BPA acknowledges that the scenario approach used in Chapter IV.B. did equate impacts with emissions. However, earlier, in Chapter IV.A., a regional air quality assessment addressing the impacts of probable coal development in the region was provided. Because the RDEIS is not site or resource specific, this approach was considered adequate. In the FEIS, an additional table and a discussion summarizing the health impacts associated with the most significant residuals from coal generation have been added to IV.B.2.d.(1)(b).

Letter No. 17, Comment No. 2

Additional information has been provided in the FEIS in IV.B.2.d.(1)(b).

Letter No. 17, Comment No. 3

Refer to Comment No. 1 of this letter.

Letter No. 17, Comment No. 4

The statement in the summary has been changed to reflect the regional potential of these impacts.

Letter No. 17, Comment No. 5

Radioactive emissions from coal-fired powerplants were mentioned in the generic section on page IV-169. However, unlike nuclear plants, these emissions vary widely with the coal being burned. It is desirable to have a reasonable method of comparing radioactive releases as to impact, but it is not yet available. Curies and even man-rem are not an answer. One curie of Krypton-85 is not as hazardous, nor is it in any way, except discharges per minute, similar to one curie of Radium-226.

LETTER NO. 18

State of Oregon; Department of Fish and Wildlife

Letter No. 18, Comment No. 1

The text has been revised to accommodate the comment.

Letter No. 18, Comment No. 2

The text has been revised to accommodate the comment.

Letter No. 18, Comment No. 3

The text has been revised to accommodate the comment.

Letter No. 18, Comment No. 4

While we are revising that discussion addressed in this comment, we disagree with the statement made here that ". . . [T]ransportation is not regarded as a successful measure . . . ." In a February 28, 1980, letter to the North Pacific Division, Army Corps of Engineers, the Columbia River Fisheries Council said, ". . . [T]he Council believes that the transportation of smolts is a worthwile endeavor and should be continued on an interim basis until safe passage is achieved." Further, the Northwest fishery agencies, supported by the Columbia River Fisheries Council, have requested an expansion of the transportation program. This request has resulted in the Corps contracting for the construction of two additional barges to be delivered in 1981 and 1982. While the collection and transportation effort has not been finalized, the success achieved to date has warranted the expenditure of over $1 million annually by the Corps and BPA for the continuance of this program.

Letter No. 18, Comment No. 5

Large numbers of birds die each year as a result of colliding with obstacles such as buildings, radio, and television transmitting antennas, and communication and power lines. For most bird species, these losses are offset by the high productivity levels of bird populations. Since 1977, BPA has sponsored three studies to assess the impact of transmission lines on birds. These studies have shown that for some lines in high bird use areas, birds regularly collide with the lines. Not all such collisions are fatal and because of the overall low frequency of collisions, mortality levels were generally not biologically significant. Furthermore, most collisions with transmission lines are thought to occur with overhead groundwires rather than conductors. These wires are not used on all lines. BPA studies are underway to develop measures for mitigating the incidence of bird collisions with transmission lines. These measures include routing and design considerations. In a few cases, existing BPA lines will be modified to reduce adverse effects on birds. Other than the data obained through the studies referenced above, seldom are reports received of bird deaths from collisions with BPA transmission lines.

Letter No. 18, Comment No. 6

Revisions to the text have been made to accommodate the comment.

LETTER NO. 19

Oregon Project Notification and Review System

No response required.

LETTER NO. 20

USPHS Department of Health and Human Services

Letter No. 20, Comment No. 1

Efforts are being made on all these fronts by many entities using the tools which are appropriate to their capabilities and authorities.

Letter No. 20, Comment No. 2

Incentives for small hydro development by non-Federal entities have been instituted. Low interest rate feasibility studies and construction loans are available from DOE and other Federal agencies. In addition, the Corps of Engineers has made a preliminary economic and environmental assessment of all potential hydro sites in the Pacific Northwest to identify those sites most probable for economical development. This should stimulate the development of the small hydro potential.

Letter No. 20, Comment No. 3

As the draft EIS indicates, no highly toxic (LD_{50} less than 50 mg/kg) or nonbiodegradable herbicides are used for brush control on powerline corridors. Some soil sterilants are used inside security-fenced station facilities and where property owners want structure sites sterilized in cultivated fields.

Intensive grazing and browsing does provide excellent vegetation control on powerline corridors. In cooperation with State and other wildlife management people, we have planted corridors with certain vegetation considered attractive to herbivores. It attracted a lot of elk and deer, but the resulting browsing pressure was insufficient to have any significant impact on the unwanted brush and trees. In the natural, uncontrolled, environment, the animals simply move on to greener pastures rather than eat less desirable food. We are investigating the possibility of controlled grazing through a research contract with Washington State University initiated in 1977. The study is incomplete, but initial results are not encouraging. The problems of confining the animals to the narrow corridors, providing them with water, preventing them from ingesting poisonous plants, etc., seem insurmountable from a practical standpoint. We do gain much vegetation control benefit in areas where local farmers or ranchers are grazing livestock under the powerlines and we certainly encourage such utilization. However, the suitable areas are limited, and it should be pointed out that the landholders frequently use herbicides for pasture improvement, particularly to eliminate poisonous weeds and unwanted brush.

Mechanical clearing may be used where the terrain is negotiable and the resulting debris is acceptable. Profuse resprouting follows mechanical clearing; this causes short control cycles. Furthermore, the large, heavy machines treat the earth rudely and may create erosion problems and consequent stream pollution. For these reasons, plus the high cost, we permit machine clearing only in special situations.

In the beginning, manual (physical) vegetation control was the only technique extant. Currently, it is again finding increasing application, partly to provide job opportunities and partly to reduce herbicide usage. Manual control could do the entire job if the necessary army of laborers could be recruited and power users would be willing to foot the bill--it is the most expensive technique by far. Yet, if all herbicides were banned tommorrow, manual control is the only alternative technique presently available.

With an eye to the future, we are seeking a research contract to investigate beyond the state-of-the-art vegetation control techniques.

BPA does have a hazardous material control program. This program is not limited to herbicides but includes all identified (by legal definition) "toxic" or "hazardous" waste. As you are aware, the Environmental Protection Agency on May 19, 1980, published in the Federal Register the Hazardous Waste Regulatory Program. BPA will comply with these requirements.

LETTER NO. 21

U.S. Department of Interior; Office of the Secretary--
Pacific Northwest Region

Letter No. 21, Comment No. 1

Refer to Letter No. 50, Comment No. 4, for a discussion of how the Fish and Wildlife Coordination Act affects Bonneville Power Administration. However, in concluding that the Fish and Wildlife Coordination Act does not apply to the marketing and transmission responsibilities of BPA, one should not infer that BPA does not feel and act upon a responsibility to protect fish and wildlife resources of the Columbia Basin.

In the Draft Role EIS (BPA, 1976), the Revised Draft EIS, the revisions included in this document, and our responses to comments to the Revised Draft EIS, BPA expresses its concern and related its activities aimed at protecting this valuable resource. Examples may be found on pages IV-18 and IV-19 of the RDEIS and in our responses to Comment Nos. 21-4, 21-5, 21-7, 35-3, and 35-7 to mention a few.

Further, BPA is actively involved in cooperative efforts aimed at protecting, mitigating, and enhancing fish and wildlife resources in the Columbia River Basin. These efforts include the rotating co-chairmanship of the Committee on Fisheries Operation, participation in the activities of the Columbia River Water Management Group, and involvement in the Corps of Engineers/Fisheries research program--the Fisheries Research and Protection Program Technical Coordination Committee. Additionally, BPA has developed a close working relationship with the Columbia River Fisheries Council through the development and conduct of the BPA Fishery Restoration Program.

Finally, as is pointed out in our response to Letter No. 50, Comment No. 4, regional energy legislation now pending before Congress would greatly expand BPA's authority and responsibilities towards the protection, mitigation, and enhancement of fish and wildlife affected by the operation of the Columbia Basin hydroelectric projects.

Letter No. 21, Comment No. 2

As stated in the RDEIS on page iv and v of the Summary section, BPA believes that "because these facilities are in place, their impacts are seen as an irreversible and irretrievable . . . ," and ". . . these impacts serve as the baseline for comparing incremental impacts of the proposal and alternatives." The discussion of the impacts relating to the existing system are, as a result, of less importance to this document. However, BPA in its initial Draft Role EIS, Appendix A, extensively covered the impact of the existing system to the environment of the Pacific Northwest and the potential impacts of future additions and alternative modes of operation. The Revised Draft EIS expands somewhat on that analysis by updating the information previously presented.

The Revised Draft EIS is a Programmatic EIS, which discusses BPA's role alternatives in the Region. As such, it does not propose any specific action other than the continued provision of services. The impact of providing these services was examined in the Revised Draft. If and when other actions, such as alternative modes of operation, are proposed, appropriate NEPA evaluation will be undertaken including mitigative and compensatory measures to alleviate potential impacts. Further, BPA's operation of the FCRPS is currently constrained within limits established by the operating agencies, e.g., the Corps of Engineers and Water and Power Resources Service. It will be BPA's responsibility to demonstrate that its actions will not violate these operating constraints. Where any BPA proposal would necessitate exceeding these constraints, BPA will conduct appropriate studies to determine the impact of the proposed action and the need for mitigative measures.

Letter No. 21, Comment No. 3

As frequently stated in the RDEIS, the major emphasis of evaluation is a generic examination of alternative institutional arrangements, i.e., alternative levels of adherence to the one-utility-concept and not an evaluation of discrete power development programs for fish and wildlife resources. The proposal presented in the EIS does effect a change in the river system. Nevertheless, Bonneville fully recognizes the biological and economic importance of the fishery resource and, consequently, has added additional information on fishery impacts and updated estimates of the economic value of this resource to the Pacific Northwest.

Letter No. 21, Comment No. 4

BPA acknowledges the value of anadromous fish to the Pacific Ocean and Columbia River Fisheries. As of calendar year 1977, the value of this resource exceeded $132,000,000 per year. This information, prepared by the National Marine Fisheries Service in August 1979, was not available at the time the Revised Draft EIS was compiled.

However, by pointing out the continued decline in the salmon and steelhead fishery, BPA has not intended to construe the Columbia River fishery resource as not being viable or an integral part of the Pacific Northwest economy. In this regard, a recent study by BPA indicates over $190 million has been reimbursed to the U.S. Treasury from FCRPS power revenues for fish protection and mitigation facilities. Further, BPA began funding fishery research and development projects in fiscal year 1978 and will have expended almost $5 million through FY 1981 on this effort. These expenditures have been made not only in recognition of the economic value of the fishery, but also in recognition of its cultural significance to the people of the Pacific Northwest.

Letter No. 21, Comment No. 5

An economic analysis of the Columbia River Fisheries Resource is beyond the scope of this document. However, BPA acknowledges the importance of this resource to the economy of the Pacific Northwest in the Revised Draft EIS on page IV-15. The value of the fishery has since increased to over $130 million as noted in other comment responses and is reflected in our revised discussion of fisheries included in the FEIS. Further, BPA has made substantial economic contributions to the preservation of this fishery through direct funding of research and development, special energy transactions, and revenues forgone for fishery flows and spills. These costs are summarized in the Committee On Fishery Operations (COFO) Annual Reports for 1977, 1978, and 1979.

The effect of the alternatives on political and institutional responsiveness, nonpower issues and power/nonpower conflicts was discussed in the RDEIS on pages IV-97, IV-101, and IV-274 respectively. Although these discussions do not specifically address the issue of "Indian treaty fishing rights," they do address possible effects on fisheries in general. Based on these discussions, the proposal would have no effect upon these treaty rights, whereas, alternatives 3 and 4 would assure their routine and formal consideration in regional power planning.

Letter No. 21, Comment No. 6

The reader is referred to Appendix A, Chapter III, pages III-116 to III-120, of the original BPA Draft Role EIS (1977), for a more comprehensive discussion on resident fisheries. Impacts to resident species are identified in the same chapter of Appendix A on pages III-169 to III-170. BPA's Role EIS will not result in any known additional impacts to resident or anadromous fish in the Columbia Basin. This document identifies a course of action for BPA to follow, within existing FCRPS operational constraints (read Letter No. 21, Comment No. 2). Any proposal to add new resources or to alter existing operations would require environmental analysis of their effect upon fisheries generally and not to resident species specifically.

Letter No. 21, Comment No. 7

This comment misses the point of our statement. Costs and technology precluded the construction of fishways at Grand Coulee Dam, and thus, precluded the continuance of an anadromous fishery resource above this project. Experience over the past few years has also shown that juvenile fish are unable to negotiate large impoundments as smolts and as a result, may residualize. (Special Drought Year Operation for Downstream Fish Migrants, COFO, 1977.) The inability of juveniles to negotiate the reservoir behind Brownlee Dam on the Snake River, eliminated anadromous fish above this project even though fish collection and passage facilities existed.

BPA's involvement in the fishery research and development program reflects our desire to improve passage conditions at mainstem Columbia and Snake River dams. While our Fishery Program is aimed at benefits to the operation of the FCRPS and the ultimate consumer of Federal power, we realize the ultimate achievement of this goal can only be reached through improved passage conditions. The specifics of BPA's Fishery Program cannot be and would not appropriately be identified in this document. Further, these studies are generally of several years duration and substantive results cannot be identified until their completion.

Letter No. 21, Comment No. 8

It would be inappropriate to cover the ongoing review of Snake River salmon and steelhead under the Endangered Species Act in the Revised Draft Role EIS (refer to Federal Register, Vol. 43, No. 192, p. 45628). The status of these and all upriver runs, as well as causative factors for their decline, has been adequately covered in Appendix III, BPA Draft Role EIS (July 1976). Additionally, Bjorn, et al (1980), Otter (1980), and Bjorn, et al (1980) provide additional coverage of the procedure leading up to and the problems associated with the listing of these upriver races as threatened or endangered.

If additional information on the endangered species review by the National Marine Fisheries Service and U.S. Fish and Wildlife Service is desired, contact the Environmental and Technical Service Division, National Marine Fisheries Service, P.O. Box 4332, Portland, Oregon 97208. Further, the most recent tabulations of run size and strengths can be found in the April 15, 1980, issue of the Columbia Basin Salmon and Steelhead Report, or the "Columbia River Fish Runs and Fisheries 1957-1978" (ODF&W, 1979).

Letter No. 21, Comment No. 9

Refer to Comment No. 2 of this letter.

Letter No. 21, Comment No. 10

The text has been revised to accommodate the comment.

Letter No. 21, Comment No. 11

Numerical displays of fishery run size were presented in Appendix A, Chapter III, BPA Draft Role EIS. We recognize that these tables are now out of date, but feel that ample information was presented at that time to portray the status of runs. As was pointed out in other comments, the current status of the runs is available from the fishery management agencies and has been widely distributed. From a nontechnical viewpoint, the April 15, 1980, issue of the Columbia Basin Salmon and Steelhead Report has the most current status of runs.

For the second part of this comment, refer to Comment No. 2 and Comment No. 6 of this letter.

Letter No. 21, Comment No. 12

We feel that the major implications of hydro peaking operations on riparian vegetation and wildlife are identified in the referenced discussion. The statement does not deny, but rather recognizes, that these impacts do occur. Additionally, it needs to be recognized that the EIS does not propose any change in river operation and it is the Corps of Engineers, not BPA, that establishes the operational parameters of the hydro facilities. For these reasons the EIS does not explore alternative modes of operation.

Letter No. 21, Comment No. 13

The statement that other listed species may exist in the area of influence is correct, and the Revised Draft EIS on pages IV-332 and IV-333 state BPA's responsibility and commitment toward this environmental concern. Bonneville's environmental procedures insure consideration for both threatened and endangered species on all major actions undertaken.

Letter No. 21, Comment No. 14

BPA is aware that water-level fluctuations may have an effect on waterfowl hunting. The discussion provided on pages IV-20 and IV-21 acknowledges this relationship. Considering that BPA does not propose to change operation of the river, the level of discussion provided was considered appropriate.

Letter No. 21, Comment No. 15

Refer to the response for Letter No. 18, Comment No. 5.

Letter No. 21, Comment No. 16

Revisions to the text have been made to accommodate the comment.

LETTER NO. 22

Idaho Consumer Affairs, Inc.

Letter No. 22, Comment No. 1

All the resource information included in Chapter IV.B.2 is presented only to develop a generic appreciation of resource types and is not intended to be a definitive, cost-based analysis used in resource selection. Accordingly, this document is not intended to serve as the sole basis for evaluating the trade-offs, economical or otherwise, between nuclear, hydropower, or any other resource type.

Letter No. 22, Comment No. 2

The Role EIS provides an assessment of environmental impacts associated with operation and development of the regional power system under various levels of regional cooperation and coordination. Because it is not the intent of the EIS to select or evaluate resources, the EIS does not include a comparison of either current or future resource costs.

Letter No. 22, Comment No. 3

At present, there is no acceptable method of comparing risks quantatively. Some excellent attempts have been made but they are not complete or consistent for all our resources. See also, Letter No. 17, Comment No. 5.

Letter No. 22, Comment No. 4

Two maps, Figures II-2 and IV-1, clearly indicate the locations of the nuclear powerplants and other generation resources within the region. Table IV-5 provides additional information concerning the cost of the thermal powerplants.

Letter No. 22, Comment No. 5

Although current and future costs are given for each resource type, the RDEIS was not intended to serve as the basis for comparing resource costs for purposes of resource slection (see response to Comment No. 1 above). Besides, there is no plan or proposal to finance future resources involving the industries.

Letter No. 22, Comment No. 6

The effect of volcanic ash fallout on a nuclear powerplant has been studied in detail by Portland General Electric (PGE) and the Washington Public Power Supply System (WPPSS). PGE has made some changes in air filtration systems at Trojan to better cope with ash problems. The studies done to date have not revealed any unacceptable problems due to volcanic ash. If additional details on the study results are desired, copies should be obtained from PGE or WPPSS.

LETTER NO. 23

Mr. John M. Gaffney

No response required.

LETTER NO. 24

U.S. Department of Agriculture; Forest Service

Letter No. 24, Comment No. 1

The efficiency of the transmission system is of great importance to BPA. Transmission losses throughout the BPA system currently average 3 to 4 percent. BPA is currently engaged in research and development on 1200-kV transmission technology. If such lines are used, this would reduce transmission system losses below that associated with 500-kV transmission lines. The 1200-kV lines will, in addition to reducing losses, require considerably less right-of-way to transmit an equivalent amount of power.

Besides conducting research on 1200-kV, BPA evaluates the existing transmission system in order to identify heavily loaded system components on which losses are excessive. BPA has, in several instances, replaced heavily loaded transmission lines and transformers earlier than planned to conserve losses. Along this same line, BPA is studying the potential of reducing energy losses in the lower voltage distribution systems of its customers. Losses typically average 10 to 12 percent in distribution systems. BPA is considering adopting a program through which it would invest in measures to reduce energy losses in distribution systems.

Underground transmission technologies are fairly well developed. BPA has, for example, installed a small section of 500-kV line underground near Ellensburg, Washington. Underground transmission is currently a very costly and high energy loss alternative to overhead lines. Further, it is expected that the impact of underground lines will exceed those of overhead lines in some environments. However, where conditions warrant, the technology is presently available to use underground transmission lines.

Innovative and new techniques of transmitting energy may develop in the future. Transmission via superconducting (low energy loss) cables, microwaves, or laser beams are currently being studied. It is considered unlikely that these technologies will be used in lieu of transmission lines in the foreseeable future.

Letter No. 24, Comment No. 2

As indicated by the text, the basic intent of Alternative 3 in providing for a "statutorily defined planning process" is to fully accommodate public input (including that from Federal agencies representing the public). Of course, BPA is also lawfully bound by NEPA to interact with affected Federal, State, and local agencies having jurisdiction or expertise in the area of concern whenever proposing any major action. Not surprisingly, the number of Federal agencies BPA interacts with in accomplishing its environmental programs are quite numerous. To list all agencies possibly involved under Alternative 3 would not contribute to the meaning of the text and would only distract from the significant issues.

LETTER NO. 25

Mr. Edward A. Mueller

Letter No. 25, Comment No. 1

At present, there is no acceptable method of comparing risks quantatively. Some excellent attempts have been made but they are not complete or consistent for all our resources.

Letter No. 25, Comment No. 2

Revisions to the text have been made to accommodate the comment.

Letter No. 25, Comment No. 3

The previous draft was widely available and BPA felt that footnoting is more appropriate than including large amounts of already existing material in the RDEIS.

Letter No. 25, Comment No. 4

The tables in question, reflect the overall environmental impact of coal and nuclear electric energy production, including the activities of extraction, transportation, processing, or conversion. (This is the trajectory approach of Equitable Environmental Health's study done for BPA.)

Letter No. 25, Comment No. 5

An accurate assessment of the firm peaking capacity of solar central station plants is not possible due to lack of data. The 10 percent figure represents the general characteristics of the solar resource. Variations of this figure will have little impact on the use of the scenario.

Letter No. 25, Comment No. 6

Revisions to the text have been made to accommodate the comment.

LETTER NO. 26

Mr. Wesley B. Prouty

No response required.

LETTER NO. 27

Mr. Don Tollefsrud

No response required.

LETTER NO. 28

Mr. Edward Ensor

No response required.

LETTER NO. 29

Mr. Phillip W. Krause

No response required.

LETTER NO. 30

Lincoln Electric Cooperative Inc.

No response required.

LETTER NO. 31

Washington Public Power Supply System

Letter No. 31, Comment No. 1

We agree with your statement regarding a "most probable" future energy resource scenario. It was in recognition of the numerous and significant uncertainties involved that we adopted the "worst case" approach which encompassed the range of probable impacts.

The introduction to the scenarios did state on page IV - 191, that resource development was dependent upon "regional planning processes." These processes as defined in Chapter III, include not only BPA, but the States, utilities, and public as well. A cross-reference to these discussions has been provided in the text.

We feel the relationship between the alternatives and impacts was clearly and specifically described in Chapter IV.D, "Impacts of the Proposal and Alternatives," and again in Chapter IV.E which provided for, and is entitled, "Summary and Comparison of the Impacts of the Proposal and Alternatives."

In addition to the references stated, ties between the alternatives and the scenarios were more clearly established in Table IV-51, "Effect of BPA's Proposal on Alternatives on Resource Development," and on pages IV-316, IV-319, IV-323, IV-325, and IV-329 of the RDEIS.

Letter No. 31, Comment No. 2

An updated March 1980 System Map has been included.

Letter No. 31, Comment No. 3

Revisions to the text have been made to accommodate the comment.

Letter No. 31, Comment No. 4

Although we appreciate the concern expressed, the advantages of maintaining the two thermal impact presentations (in terms of the scenario comparisons, for example) justify the distinction. However, additional cross-referencing has been provided in IV.A.1.

(See also, Comment No. 8 of this letter.)

Letter No. 31, Comment No. 5

Revisions to the text have been made to accommodate the comment.

Letter No. 31, Comment No. 6

The discussion of impingement in the text has been revised. For a discussion on thermal effects, refer to the area in the text which was changed in response to Comment No. 5 of this letter.

Letter No. 31, Comment No. 7

Revisions to the text have been made to accommodate the comment.

Letter No. 31, Comment No. 8

We recognize that the regional resource impact discussion is inconsistent. This is due to the varying levels of impact information available from technologies that are at various stages of development and the variations due to site specific characteristics.

Although, as noted, some impacts vary only by degree, other impacts vary considerably between technologies. As a result, we feel a table summarizing impact differences between 12 energy resources would be cluttered and would not add clarity to the existing discussion.

Since most of the energy technologies discussed were not available for commercial operation in 1970 and several still will not be in operation by 1985, only sketchy cost data would be available for a table. We feel the existing cost discussion for each technology is adequate for a generic discussion.

Letter No. 31, Comment No. 9

In preparing the Revised Draft Role EIS tables, data from the Equitable Environmental Health Report - "Environmental Impacts of the Generation of Electricity in the Pacific Northwest" was used. We felt by using numbers generated from one source, impact comparisons between the various technologies would be more meaningful than comparing numbers obtained from several different sources. Although our figures might be a little high, they are technically suitable for the generic level of this EIS.

Letter No. 31, Comment No. 10

Revisions to the text have been made to accommodate the comment.

Letter No. 31, Comment No. 11

The 333,000 tons year of suspended/dissolved solids was taken from Table V-55 in the Draft Role EIS. Even though the suspended/dissolved solids are discharged into a pond for settling and are not directly discharged into a natural water body, they are still considered part of the water effluent.

Letter No. 31, Comment No. 12

Revisions to the text have been made to accommodate the comment.

Letter No. 31, Comment No. 13

Revisions to the text have been made to accommodate the comment.

Letter No. 31, Comment No. 14

Revisions to the text have been made to accommodate the comment.

Letter No. 31, Comment No. 15

The figures in these tables are upper limits and are used to evaluate the maximum environmental impacts of a technology. Since 70 tons/year is the maximum yearly discharge allowed under the National Pollutant Discharge Elimination System permit, this figure was used in Table IV-45. To clarify that these impacts include the entire generation trajectory, Table V-55 of the Draft Role EIS has been incorporated into the Final EIS. See also response to Comment No. 4 of this letter.

Letter No. 31, Comment No. 16

In spite of the fact that the EIS was reduced from five volumes to one, we recognize that some repetition still exists. However, in reference to the citation given, the same material was felt to be essential to the development of the different headings. As indicated in your first comment, there was a concern that it was necessary to have certain points explicitly stated to minimize the possibility of being overlooked by the reviewer.

LETTER NO. 32

Industrial Customers of Bonneville Power Administration

Letter No. 32, Comment No. 1

In the absence of new legislation, BPA's allocation policy will indeed impact the regional power system. An assessment of the allocations policy is nearing completion. These issues along with many others were raised during the "scoping" process on the allocations assessment. Accordingly, they are being considered in the development of that document.

Letter No. 32, Comment No. 2

The programatic coverage of the Role EIS is intended to cover each of these actions at least in terms of the "day-to-day" arrangements necessary to operate the regional power supply system. As noted in Chapter III under the proposal, BPA is not proposing to enter into any new, long term, trust agency arrangements. BPA recognizes that proposed in the future, such arrangements would have to be assessed individually. Although separate EIS's may not be necessary, these actions would have to be examined individually to insure that the Role EIS, for example, adequately addresses their impacts.

Letter No. 32, Comment No. 3

The Revised Draft EIS gave a full discussion on direct-service industries in Chapter IV, A.2e. Thirteen pages were utilized to described the role of the DSIs' and their effect upon the regional power system, including the benefit of providing reserves. For the purpose of the Role EIS, the information given more than adequately covers the circumstances surrounding DSIs and their participation in the regional power system.

Letter No. 32, Comment No. 4

The generic discussion of advanced energy has been expanded in the Final EIS to more fully describe these types of agreements. Much of this material was initially presented in Appendix A of the original Draft EIS.

Letter No. 32, Comment No. 5

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 6

Having two separate tables of contents would only cause confusion. Both extremes, simple and complex, were considered when developing the format. The simple version was not sufficient enough to meet the diverse interests of the people reviewing the document. The complex style became so cumbersome that it interfered with easy identification and location of material being sought. The format which appears in the Role EIS is considered the best blend of both simple and complex, offering easy access to essential material.

Letter No. 32, Comment No. 7

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 8

The answers to this question require speculation as to the likelihood of alternative scenarios. One possible scenario would be that individual preference utilities would finance, construct, and operate resources through generating entities such as the Pacific Northwest Generating Corporation or the Washington Public Power Supply System. Another scenario is that which is described in the comment, with, after a period of disarray, the various regional utilities being consolidated through State power authorities such as that currently under investigation in Oregon. A number of outcomes, intermediate to these scenarios, are also possible.

What would finally evolve would be dependent upon the influence of a number of factors including among others: (1) the long history of cooperative interaction among regional utilities; (2) the increasing political desirability of local control over utilities and government; (3) the severity and duration of power shortages; and (4) the significance of rate diversities among utilities. If one were to predict the future based on a simple trend of historical experience, it appears to Bonneville that the "one utility concept" would give rise to new institutional and contractural arrangements to meet the new problems. And, based upon regional experience, these arrangements most likely would tend to preserve local utilities while allowing them to mutually realize the economics and efficiencies of single utility operations.

<u>Letter No. 32, Comment No. 9</u>

BPA's position on this point is that every kilowatthour (kWh) is a new kWh, including those supplied to the DSI's. In other words, DSI loads along with the demands from other entities including the utilities were collectively seen as necessitating new powerplant construction under the Hydro-Thermal Power Program. Recognizing this, it can be said that if the DSI's reduced their consumption, there would be less need for additional generation.

<u>Letter No. 32, Comment No. 10</u>

In the absence of new legislation, BPA's allocation policy will indeed impact the regional power system. An allocations assessment is nearing completion. These issues along with many others were raised during the "scoping" process for the allocations assessment. Accordingly, they are being considered in the development of that document.

<u>Letter No. 32, Comment No. 11</u>

We agree with the statement. However, as stated in the RDEIS on page I-20, before Bonneville can determine what its obligations are under NEPA, it must first review project or program proposals from an environmental standpoint. This review may or may not result in a formal NEPA document (EIS or EA).

Letter No. 32, Comment No. 12

Bonneville agrees with this statement. Although it is our intention to reflect this attitude in the record of decision, the emphasis given in the document is felt appropriate.

Letter No. 32, Comment No. 13

The summary of the Role EIS preceding the Table of Contents and Chapter IV.E.7, explain the reasons Alternative 3 is considered the "environmentally preferable alternative." The discussion presented in these two areas is sufficient to inform the reader.

Letter No. 32, Comment No. 14

This point was made in the introduction to the alternatives discussion on page III-35 of the RDEIS.

Letter No. 32, Comment No. 15

An appreciation of this particular point is critical for understanding the approach taken in the EIS.

Letter No. 32, Comment No. 16

Although we agree with this position, a summary of NRDC's alternative scenario has been included in the Final EIS along with the other resource scenarios.

Letter No. 32, Comment No. 17

Perhaps the problem here is one of perspective. Depending on one's point of view, there is either a good deal of cooperation going on within the region, or the current level of cooperation/coordination leaves something to be desired.

Letter No. 32, Comment No. 18

This comment notes that the draft fails to address the customer services which would be provided to DSIs. The comment is well taken and changes in the text have been made for services addressed i.e., load factoring services, forced outage reserves, load growth reserves, and trust agent power purchases and surplus sales. Bonneville presently and will continue to provide two of these four services to the DSIs. For the past several years Bonneville has provided load factoring services and trust agent services to the DSIs in the purchase of industrial replacement energy. These services are currently provided under industrial replacement energy agreements which can be terminated on 1-year's notice. Through these agreements Bonneville provides load factoring services for contract purchases of non-Federal energy by the DSIs. Bonneville also acts as a trust agent by arranging these purchases for the DSIs and by arranging sales of surplus IRE energy when it is no longer needed by the DSIs.

Letter No. 32, Comment No. 19

The statement quoted, refers to the disposition by sale (as opposed to exchange) of services which would decrease the amount of energy to be sold by Bonneville. Such a situation would require an allocation in accordance with the preference and priority granted public bodies and cooperatives by law. To do otherwise, would be to effectively dispose of Federal energy contrary to law.

This is not to say, however, that only public bodies or cooperatives would then receive such services. It may be that preference customers could not meet service criteria for receipt of some portion of the available services and, therefore, some or all of the service available may be sold to nonpreference entities. Also, there may be circumstances where the exchange (as opposed to sale) of such services will enhance the economical and efficient operation of the Federal Columbia River Power System. This latter case is addressed in the RDEIS immediately below the language quoted in this comment.

Letter No. 32, Comment No. 20

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 21

BPA agrees that utilities should not be given improper incentive to rely upon the reserves rather than developing adequate resources. The total amount of load growth reserves available is limited to one-half of the region's average annual utility load growth and the charge reflects the cost of power purchased or reserved. BPA feels this cost is sufficiently high enough as to not encourage indiscriminate usage.

Letter No. 32, Comment No. 22

The answer to Comment No. 18 of this letter addresses Bonneville's role in assisting the DSI's to purchase replacement energy. The policy of pro-rata restriction is beyond the scope of the EIS.

Letter No. 32, Comment No. 23

Because BPA is not proposing to utilize long term trust agency arrangements, the referenced text was not changed. However, arrangements of this type are considered feasible under Alternatives 3 and 4 since both these alternatives would require BPA to acquire the resources necessary to meet customer loads.

Letter No. 32, Comment No. 24

BPA anticipates validating each utilities' individual forecast under those conditions where Federal programs are affected. The proposed Allocation Policy indicates those conditions. Definitive utility forecasts that are approved by BPA will be necessary for determining base allocations, total allocations, reserve energy allocations, and for some preference customers, the offset energy which will be at purchase costs different from pro-rata allocations. Conservation elements contained in the Policy would demand detailed information by consumer sectors for deteriming how and where conservation savings can be achieved.

In the event a Regional Bill should be enacted, BPA would be required to analyze each individual utility's loads and resources to permit the fulfillment of Section 6(m) of H.R. 6677 regarding major resource acquisitions.

Letter No. 32, Comment No. 25

The emphasis given is felt appropriate.

Letter No. 32, Comment No. 26

The second paragraph on page III-18 of the RDEIS under the heading, "Definition of Conservation," made the same point.

Letter No. 32, Comment No. 27

Although BPA endorses conservation efforts/investigations, for the reasons given in Chapter I - Overview, pages I-25 to I-27, Bonneville did not feel it was appropriate to designate Alternative 3 as its proposal.

Letter No. 32, Comment No. 28

The text has been clarified. However, the Revised Draft EIS did imply cost-effectiveness by stating that BPA defines conservation to include minimizing costs. Cost-effectiveness was also specifically mentioned on pages III-18, III-21, and III-22.

Letter No. 32, Comment No. 29

We agree. The consequences identified are precisely those identified under Alternative 2 which begins on page III-44 of the Revised Draft EIS.

Letter No. 32, Comment No. 30

The RDEIS did explain the value of the industrial reserve to the region in Chapter IV.A.2.e. (pages IV-69 to 82). However, the belief that BPA can continue to directly serve DSI customers utilizing similar contractual arrangements under an allocation policy and in the face of conflicting applications from a preference customer is an option that BPA does not believe it has available.

The second question regards whether BPA may market a class of power which is attractive to serve industrial loads. The answer is yes, provided; (1) that the development of the class of power is justifiable on the basis of the efficient and economic operation of the Bonneville system, and (2) that it is not designed for the purpose of creating an allocation in derogation of the preference clause. The class or classes of power created are, of course, subject to the preference clause and applications for such power made by preference bodies should be accorded priority.

Letter No. 32, Comment No. 31

In order for an allocation methodology to impact the operation of generation sources and the mutually beneficial exchanges with other regions, substantial changes would be required in the nature of the load that is served. Otherwise, the same generation sources will be serving the same area loads in the same manner. The method of delivery may be different and the cost of generation may vary to individual customers, but the loads will be served by the same resources as before. No new resources are to result directly from BPA's allocation policy, and since BPA presently operates to sell all available capacity, no obligation can be met to service additional loads.

BPA studies indicate that in the unlikely event that the DSI load disappears from the region, steps can be taken through modification of our power sales contracts (which by their nature of delivering capacity during the daytime and receiving energy back at night force greater fluctuations in our loads) to mitigate the impact of domestic load fluctuations. As stated earlier, operation of the FCRPS is limited by both the amount of capacity available to be sold and by the nonpower constraints specified by the Corps of Engineers, plus each hydro project's specific license.

Letter No. 32, Comment No. 32

A legal issue related to this comment pertains to how a DSI load will be treated by a retail utility under the allocation policy. This is a matter concerning State law, which BPA has no special expertise. It is expected that the question of utility responsibility will vary throughout the States comprising the BPA service area. BPA has recognized the benefits of and need for the reserves provided by existing contracts with former DSIs by providing for the marketing of a separate class of system reserve energy, subject to the preference clause, in its proposed allocation policy published in the Federal Register on October 5, 1979 (44 FR 57824). In addition, the proposed allocation policy allows a preference customer to include in its firm loads which are eligible for allocation, the bottom two quartiles of any DSI load located adjacent to or within its service area.

Letter No. 32, Comment No. 33

Chapter IV, A.2.e, gives an evaluation of the environmental impacts related to energy reserves. The impacts associated with the reserves are felt to be clearly stated. Additionally, there are frequent references throughout the Role EIS which allow the reader to keep in mind the significance of reserves. BPA appreciates the concern the DSI's have for the importance of energy reserves on the regional power system, but Bonneville believes the coverage of the reserves as presented in the Revised Draft EIS is adequate.

Letter No. 32, Comment No. 34

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 35

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 36

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 37

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 38

Refer to the response for Comment No. 33 of this letter.

Letter No. 32, Comment No. 39

Refer to the response for Comment No. 33 of this letter.

Letter No. 32, Comment No. 40

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 41

Bonneville considers the entire loads of its Direct-Service Industrial (DSI) customers as firm loads, subject to restriction. Although secondary energy can be used to meet DSI loads under the industrial firm or modified firm rate schedules and is considered for the purposes of the sale as industrial firm or modified firm power.

It is not true that use of secondary energy to meet top quartile industrial loads has reduced the costs of power to Bonneville's other customers. In the cost-of-service study prepared for the 1979 wholesale rate filing, costs were allocated to the portion of the top quartile DSI load that Bonneville anticipates it will meet. Therefore, revenues received from sales of power to meet DSI top quartile loads should cover costs incurred in serving the loads.

The DSI secondary energy sales listed in Table IV-9 include sales of authorized and unauthorized increases made under the IF-1 schedule and nonfirm energy sales made under the H-5 schedule.

Letter No. 32, Comment No. 42

The text was updated to reflect the fact that Bonneville's 1979 Wholesale Rate Schedules are the rate schedules currently in effect. The Federal Energy Regulatory Commission granted interim approval of the 1979 Wholesale Rate Schedules in December 1979.

Letter No. 32, Comment No. 43

The text was modified to indicate that impacts of Bonneville's rate increase are due primarily to higher rate levels rather than different rate structures. Bonneville is unaware that the design of the availability credit has significantly impacted the DSIs.

Letter No. 32, Comment No. 44

A lengthy discussion about the regional reserves and operational benefits provided to the Federal Columbia River Power System by direct-service industries was included in the text (Chapter IV, pages 69-80) of the RDEIS. It is not necessarily true that direct-service industries pay system average rates despite below average cost of service. The 1979 cost-of-service analysis indicated that on a per kilowatthour basis, it cost Bonneville just as much, if not more, to serve its direct-service industrial customers as it does to serve its public agency customers.

Letter No. 32, Comment No. 45

Changes to the text have been made since the comment is conceptually correct. Industrial firm power is a single class power with each kilowatt being subject to varying degrees of restriction. The importance of this distinction is that Bonneville treats the entire class of industrial firm power as firm power for the purposes of planning the needs of the system. However, the draft is technically correct. The IF Contracts do divide DSI contract demand into quartiles for the purpose of exercising restriction rights.

Letter No. 32, Comment No. 46

BPA bases its sales on firm energy projections for a critical water year. This quartile is not usable for reserve during critical water since it is only served when there is adequate secondary (surplus) energy.

Letter No. 32, Comment No. 47

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 48

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 49

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 50

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 51

This EIS is not intended to provide the environmental analysis for specific contracts on provisional energy or any other specific service or contractual arrangement. Rather, it is intended to address services in a generic manner. Subsequent individual contracts, their provisions, and impacts will be subject to individual environmental review.

Letter No. 32, Comment No. 52

Changes to the text have been made. Both the draft and the comment were inadequate. IF agreements are bilaterally negotiated agreements whereby Bonneville sells and the DSIs purchase reserves provided by the restriction rights in the contracts. Whether the DSIs would prefer to receive service on a firm basis is irrelevant since such service was not available for the proposed 20-year term of the IF agreements. The IF agreements were to provide that the DSIs trade some of the firm power they were entitled to under the MF contract for the reserves sold under the IF agreements. If the restriction rights are exercised to provide reserves, the availability credit provided in the IF agreements provides compensation to the DSIs to purchase replacement energy.

Letter No. 32, Comment No. 53

BPA does not feel that classification of restriction rights as energy or capacity reserves will impact the clarity of the discussion.

Letter No. 32, Comment No. 54

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 55

This point has been added to the discussion of second quartile provisions contained in IV.A.2.e.

Letter No. 32, Comment No. 56

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 57

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 58

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 59

Revisions to the text have been made to accommodate the comment. (Refer to the next comment, also.)

Letter No. 32, Comment No. 60

The discussion of advance energy in the text has been expanded. However, the "sufficiency" of the Role EIS from a NEPA standpoint can only be determined upon an examination of a specific provisional energy agreement and comparing its provisions with those addressed in the Role EIS.

Letter No. 32, Comment No. 61

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 62

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 63

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 64

Although the DSI's are in compliance with Federal, State, and local environmental standards, environmental impacts are associated with the plants. BPA has done two EIS's on DSI plants to date, illustrating that actions related to serving these plants reflect, "actions significantly affecting the quality of the human environment." Appendix C of the original "Role EIS" demonstrates that the cumulative effects of the DSI's are significant.

Letter No. 32, Comment No. 65

The Role EIS was not written to specifically evaluate the consequences (advantages/disadvantages) of overbuilding vs. underbuilding.

Instead, these occurences were presented as possible results of alternative institutional arrangements. Accordingly, the discussions on pages IV-99 and IV-100 and pages IV-247 to IV-251 of the RDEIS are felt to sufficiently address the possibilities as they apply to the proposal and alternatives.

Letter No. 32, Comment No. 66

BPA agrees that the region cannot excessively rely on the possibility of imports to meet our forecasted deficits. Paragraphs 3 and 6 on IV-99 of the RDEIS point out that the hydro system will be run much tighter and pressure for new generating resources will increase if imports are not available at a reasonable price or in sufficient quantity. In compliance with the National Energy Policy, oil-fired generation would be one of the last resorts.

Letter No. 32, Comment No. 67

This point is not only made on page IV-99, but again under the discussion of impacts the proposal and alternatives have on future resources which begins on page IV-248 of the RDEIS. Another consequence of regional energy deficiencies not identified in the comment would be a reliance upon energy imports from outside the Pacific Northwest. This possibility was presented in the RDEIS under the impacts of the proposal and alternatives on interregional transaction effects beginning on page IV-267. In all, we feel the consequences of this type of resource imbalance are sufficiently emphasized in the document.

Letter No. 32, Comment No. 68

As described on page IV-191 of the RDEIS, these scenarios are regarded as "worst case" only in terms of their reliance upon a given resource type technology.

This approach was utilized precisely because the ultimate resource mix or even the probable potential of different resources (theoretical vs. practical) is not known (page IV-192). Bonneville is currently investigating these potentials. Once determined, these potentials will be the basis for future resource projections.

Letter No. 32, Comment No. 69

The text has been changed to accommodate the comment.

Letter No. 32, Comment No. 70

The text has been changed to accommodate the comment.

Letter No. 32, Comment No. 71

See Comment No. 68 of this letter.

Letter No. 32, Comment No. 72

The impacts of not serving the DSIs are considered clearly identified in the RDEIS. Given the context of the Role EIS, these discussions are given appropriate emphasis. However, the Allocations assessment will examine this issue in more detail.

Letter No. 32, Comment No. 73

As stated on page IV-81, ". . . BPA's DSIs have significant impacts on the region's physical environment." Given this, the statement on page IV-234 does not seem at all misleading.

Letter No. 32, Comment No. 74

Direct-service industries are not Bonneville's only high load factor customers. Certain preference customers also have high load factors and do not benefit from a pricing structure under which a relatively greater proportion of cost is collected from the energy rate than from the capacity rate. However, under Bonneville's 1979 Wholesale Rate Schedules, customers with a high load factor still experience a lower average per kilowatthour cost than customers with a lower load factor.

Bonneville believes that its rates should communicate a price signal to its customers which makes them aware of the relative costs involved in producing additional increments of specific components of service. In an energy-short system, each increment of energy purchased, be it by a high load factor customer or a low load factor customer, contributes to the need for new generation resources. If Bonneville provides correct price signals to its customers and these price signals are passed through to end-users of the power, conservation may be encouraged.

Letter No. 32, Comment No. 75

Bonneville did not reject conservation rate incentives in its determination order on the Public Utility Regulatory Policies Act ratemaking standards. It was stated in the order that, although Bonneville will always consider an embedded cost-of-service analysis in designing rates, it will also consider other factors including purposes of conservation and efficient use of resources.

Letter No. 32, Comment No. 76

The analysis presented in the EIS supports this conclusion.

Letter No. 32, Comment No. 77

Consistent with our legal charter, BPA's policy regarding the distribution of secondary energy has been formulated in terms of customer type rather than the type of load being served by the various sources of generation. Public agencies' needs within the BPA marketing area have the highest priority. Should there be additional secondary energy available, it is distributed equitably between Northwest Direct-Service Industries and Investor-Owned Utilities. This policy does not preclude any utility from adopting a strategy of planning the use of combustion turbine generation to serve a load (firm or interruptible) but with the anticipation that the generation will be displaced by hydro secondary energy.

Letter No. 32, Comment No. 78

See Comment No. 1 of this letter.

Letter No. 32, Comment No. 79

See earlier response to Comment No. 22 of this letter.

Letter No. 32, Comment No. 80

Given the fact that this issue is presented in Chapter IV.C and again in IV.D.1.b, the emphasis is felt appropriate.

Letter No. 32, Comment No. 81

See Comment No. 2 of this letter.

Letter No. 32, Comment No. 82

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 83

The text has been rephrased.

Letter No. 32, Comment No. 84

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 85

As a practical matter this would appear to be true. However, given the structure of the proposal, the possibility does exist whereby the region could encounter a resource surplus.

Letter No. 32, Comment No. 86

The discussion about replacing thermal generation with hydro under surplus water conditions has been modified to indicate that thermal power would be displaced by hydro power when the savings in variable costs exceeded the costs of idling the thermal plants.

Bonneville's 1979 Wholesale Nonfirm Energy Rate Schedule is designed to provide operators of thermal plants with sufficient economic incentive to purchase nonfirm energy from Bonneville while continuing to operate their low-cost thermal plants and to use the output from these resources to displace relatively higher cost Southwest oil-fired thermal.

Letter No. 32, Comment No. 87

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 88

Revisions to the text have been made to accommodate the comment.

Letter No. 32, Comment No. 89

The text has been revised to reflect BPA's current allocation proposal, which was published in the Federal Register on October 5, 1979. (See IV.D.3.b., which summarizes the current allocation proposal.) In spite of the fact that BPA now has a proposed allocation policy we still feel it is useful to present a range of alternative allocation policies. However, as discussed on page IV-297 of the Revised Draft, the basic point being made is that the proposal and Alternatives 1 and 2 require a BPA allocation. This fact distinguishes them from Alternatives 3 and 4, which provide for the acquisitiuon of necessary resources, obviating the need for an allocation.

Letter No. 32, Comment No. 90

BPA has no obligation to recognize DSI loads as existing loads eligible for an allocation of BPA power. The Administrator has discretion under the Santa Clara decision to pick and choose between preference customers and, as a corollary, to decide the question of which existing customer loads or portions thereof will be recognized as eligible for an allocation. (City of Santa Clara v. Andrus, 572 F. 2d 660, 670 (1978), cert. denied 99 S. Ct. 176 439 U.S. 859 (1978). The Administrator has exercised this discretion in specifying types of loads to be served and in electing to create a class of system reserve energy subject to BPA interruption and preference criteria in BPA's proposed allocation policy published in the Federal Register on October 5, 1979 (44 FR 57824). In addition, the proposed allocation policy allows a preference customer to include in its firm loads eligible for allocation the bottom two quartiles of any DSI load located with or adjacent to its service area.

Letter No. 32, Comment No. 91

Refer to previous comment response.

Letter No. 32, Comment No. 92

The text has been changed to accommodate the comment.

LETTER NO. 33

Mr. Frank L. Campbell

No response required.

LETTER NO. 34

Gaffco Farms, Inc.

No response required.

LETTER NO. 35

State of Washington; Department of Game

Letter No. 35, Comment No. 1

The appropriate context to evaluate specific fishery mitigation measures would be project or program proposals that would affect this response. Since the proposal in the Role EIS does not affect this resource, mitigation/compensation measures were not considered. However, when examining the institutional alternatives presented in the document consideration was given to the effect upon "non-power" considerations, including fish.

It should be noted, however, that BPA has spent considerable time reviewing the impacts of the development of the FCRPS on the environment, especially the salmon and steelhead resource. Appendix A, Chapter III, of the BPA Draft Role EIS (July 1977) summarizes these impacts and lists bibliographical information on the source of our materials. Obviously, a considerable amount of information has been developed since the initial publication of the Draft EIS and the Revised Draft EIS. Many of these references are identified in the revised discussion on Fisheries.

Letter No. 35, Comment No. 2

Additional information relative to fishery impacts has been included in the FEIS. This information, along with that previously provided, is intended to depict the impacts associated with the operation of the existing system. Although the impacts of the proposal and alternatives were evaluated against those impacts associated with the existing system, this was in no way intended to downplay the impacts of the latter.

Refer, also, to Letter No. 21, Comment No. 2.

Letter No. 35, Comment No. 3

BPA is actively involved in annual operations to protect juvenile migrant salmon and steelhead. It has been BPA's policy to provide as much of the requested flow and spill as possible without jeopardizing firm energy resources and the refilling of the Federal storage reservoirs. As was pointed out in our response to Letter No. 50, Comment No. 29, costs and revenue losses to BPA in providing spills since 1977 have been substantial. Annual costs of providing flow and spill since 1977 have ranged from less than $1 million during 1978 to almost $5 million in 1980.

The operation of the Federal Columbia River Power System (FCRPS) is maintained within established constraints. While not all of these operating constraints are environmentally based, many are, and a substantial number of these are for the protection of fish and wildlife. BPA recognizes that any proposed change in operation that violates or would alter one of the existing constraints, would require appropriate environmental review. It is also unlikely the Corps of Engineers or the Water and Power Resources Service would alter the existing constraints without biological evidence indicating no further degradation of fish and wildlife would occur.

BPA is currently pursuing the alteration of existing winter/summer minimum flows in the Snake River. If our study, being undertaken by the National Marine Fisheries Service, proves that storage of water in reservoirs during offpeak and weekend hours does not impact adult salmon and steelhead migration patterns, then minimum flow constraints might be altered.

The point of this discussion is that the option exists to alter the constraints which determine the operation of the FCRPS. Constraints can be strengthened or relaxed as a result of biological studies or public desires. BPA's responsibility is to market energy produced by the FCRPS within existing operational constraints. BPA does not establish these constraints and can operate the individual projects only within established limits.

Letter No. 35, Comment No. 4

Impacts of the various operating regimes are presented in the Revised Draft beginning on page IV-15. This Revised Draft, in summarizing the more detailed discussion of Appendix A, Draft Role EIS, addressed impacts of the hydrosystem to: 1) fisheries, 2) riparian wildlife, 3) water quality, 4) recreation, 5) visual and esthetic values, 6) cultural resources, 7) irrigation, 8) navigation, and 9) community services.

Chapter IV of the Revised Draft serves as the impact analysis portion of this document. Coverage has been given to the existing system (IV.A.) and future system development (IV.B.), as well as the impacts associated with the proposal and alternatives (IV.D.). It is our belief that we have in fact addressed environmental and social impacts of the proposal to a level consistent with the scope of this Role EIS.

Letter No. 35, Comment No. 5

The text has been revised to accommodate the comment.

Letter No. 35, Comment No. 6

Mitigation referred to here are those measures taken as a result of the construction of hydroelectric facilities on the Columbia River and its tributaries. From the Federal perspective, over $220,000,000 has been expended on fish facilities at Corps of Engineers and Water and Power Resources Service projects in the Columbia River. Of this total, approximately $193,000,000 has been repaid to the U.S. Treasury from FCRPS revenues. Direct expenditures by the Corps of Engineers for operation and maintenance of facilities have been over $25,000,000, while BPA has funded approximately $5,000,000 on R&D projects since FY 1978.

Mitigation facilities include fish hatcheries, adult collection and passage facilities, spillway deflectors, juvenile bypass/collection facilities, and other items intended to mitigate losses caused by the individual projects or a series of projects. An example of mitigation for a series of projects is the Lower Snake River Compensation Plan. This Plan, initiated in FY 1978, is intended to mitigate losses caused by the construction and operation of the Corps of Engineers complex of dams on the Lower Snake River, including the Ice Harbor, Lower Monumental, Little Goose, and Lower Granite facilities. This Plan alone is expected to cost over $160,000,000 upon completion and will result in the annual return of over 130,000 adult salmon and steelhead to the Snake River.

Letter No. 35, Comment No. 7

As pointed out in our response to Comment No. 6 above and as reflected in the revised discussion on fisheries in this document, BPA has funded research aimed at protecting and enhancing Columbia River salmon and steelhead. While some might feel BPA should assume responsibility for the mitigation of damage caused by Columbia Basin multipurpose dam development, the fact remains that BPA did not construct these projects. As an authorized project purpose of the Federal Columbia Basin hydroelectric projects, revenues from the FCRPS repay a significant portion of mitigative measures at these dams. As pointed out in our response above this has amounted to over $193,000,000 through the end of FY 1979. Under existing authorities and with deference to existing responsibilities, it is highly unlikely that BPA could directly fund mitigative measures for Columbia Basin salmon and steelhead.

Letter No. 35, Comment No. 8

In addition to our response to Letter No. 18, Comment No. 4, refer to Appendix A, Chapter III of the BPA Draft Role EIS. Pages III-73 to III-88 summarize the Region's artificial production effort. More recently, this listing has been revised in the State of Washington, Department of Ecology's "Columbia River Instream Resource Protection Program." The economic value of the Fishery resource to the region is reflected in the most recent projection of the cost to complete the Lower Snake River Compensation Plan. In his February 4, 1980, letter to Sterling Munro, Colonel H. J. Thayer, District Engineer for the North Pacific Division, Corps of Engineers, indicated the total cost of this Plan was expected to exceed $160 million. This is in addition to over $220 million previously spent by the Corps for fisheries mitigation as a result of their construction activities.

Letter No. 35, Comment No. 9

We agree.

Letter No. 35, Comment No. 10

Although it can be expected that additional units would have an effect upon juvenile mortality rates, the referenced discussion was intended to discuss water quality only. However, since the Mid-Columbia projects will require amendment to their FERC licenses to install additional generation, the public will have ample opportunity to comment regarding adequate protection measures for fish. Additionally, ongoing FERC Settlement Agreements at the Vernita Bar and the other Mid-Columbia projects are designed to improve fish passage conditions. It is likely fish passage conditions will improve as a result of these and related actions.

Letter No. 35, Comment No. 11

BPA recognizes the fact that impacts on riparian vegetation do exist during hydro peaking operations. Pages IV-18 and IV-19 in the Revised Draft EIS directly address this concern. The section referenced by this comment is a discussion of the socioeconomic impacts and not the biotic impacts.

Letter No. 35, Comment No. 12

The text has been previously expanded to include further references to the Draft Role EIS regarding hydro-thermal coordination impacts. (DEIS A:II-75 to II-85). The fact that additional base load thermal plants will increase the hydrosystem fluctuations (all other things being equal) is admitted and dealt with at some length in both the Draft and the Revised Draft EIS.

Letter No. 35, Comment No. 13

We believe our statement on page IV-78 accurately conveys the concerns of this comment. All of the points identified relative to sport fisheries, increased temperature and turbine flow, as well as other impacts have been identified in the Revised Draft EIS.

Letter No. 35, Comment No. 14

The objective of this discussion is not to present an evaluation of the individual industrial plants, but rather to describe their cumulative relationship and impact to the regional power supply system as a whole (RDEIS, page IV-73). However, a list of the DSI's by name is contained in Table IV-11.

Letter No. 35, Comment No. 15

BPA has conducted an extensive review of the effect of electric fields on wildlife and domestic animals. No convincing evidence that wildlife is noticeably affected by electric fields was discovered. A review of electrical and biological effects of transmission lines has been published by BPA. Copies of this review are available on request.

Letter No. 35, Comment No. 16

In order to more effectively evaluate the alternatives considered, it is felt essential to integrate all nonpower considerations. Following this approach will provide a clearer contrast between power and nonpower considerations and, consequently, between the alternatives themselves.

Letter No. 35, Comment No. 17

As indicated on page IV-101 of the RDEIS, it is expected that a regional resource insufficiency might result in a relaxation of existing nonpower constraints. Given a resource surplus, the opposite would be true.

Letter No. 35, Comment No. 18

The discussion referred to is not the discussion of effect or impact. That discussion is contained on pages IV-1 through IV-92. It is assumed, having read these preceding pages, that it is not necessary to restate these impacts here. Also, as is pointed out in several of the responses, Appendix A of the July 1977 BPA Draft Role EIS went into considerable detail identifying "operating" impacts.

Letter No. 35, Comment No. 19

Given a regional perspective, it is felt that a real interrelationship between the consideration of nonpower issues and the operation of the regional power supply system in those situations is described in the text.

Letter No. 35, Comment No. 20

Again, this discussion is not intended to duplicate the discussion of the effect contained in Chapter IV.A. Since the document does not propose the selection of any resource, and the information on alternative resource types is included only to give a generic appreciation of their impacts, we feel the coverage is adequate.

Letter No. 35, Comment No. 21

Revisions to the text have been made to accommodate the comment.

Letter No. 35, Comment No. 22

The basic relationship between power production and wildlife is not being disputed. This statement simply represents the fact that the "specific" relationship, in terms of the degree of impact involved, is uncertain when, for example, recreation and aesthetics are being considered.

Letter No. 35, Comment No. 23

As required by the CEQ regulations (Section 1502.13), the proposal and alternatives included in the Role EIS are designed around the statement of purpose and need as presented at the beginning of the document.

LETTER NO. 36

(FERN) Fair Electric Rates Now

Letter No. 36, Comment No. 1

See discussion for Comments No. 2, 3, and 7 of this letter.

Letter No. 36, Comment No. 2

The melded rate concept is contained throughout the legislative history associated with BPA. In a legal opinion, Bonneville's General Counsel concluded that BPA 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 powerplants owned and constructed by non-Federal interests and to "meld" or average the cost of this thermal power in its power rates. Congressional approval may be required prior to any abandonment of the melded rate concept.

For additional dicussion of this topic, please refer to Attachment C, page C-36 and following.

Letter No. 36, Comment No. 3

The statutes under which BPA operates require that preference and priority be given to public bodies and cooperatives in the sale of FCRPS power. The Bonneville Project Act, Section 4(a), states that: "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 customers, 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 the first three decades of BPA's operation many voters in the Northwest States elected not to establish public bodies and cooperatives. This choice was based as much, if not more, on political ideology as on power costs, since BPA had sufficient power to meet the needs of investor-owned utilities as well as preference customers.

Since 1940, DSI customers have played a fundamental role in the development of the regional power system. The DSI's have provided a market for secondary energy not usable by utility customers due to its unpredictable availability. Since 1965, Bonneville has also had restriction rights on certain amounts of DSI contract demand. DSI's also provide a portion of the region's power reserves.

At the present time, BPA does not have a proposal for long-term service to the DSI's. In 1976, the companies were notified that their power sales contracts would not be renewed upon expiration as there is a lack of resources to meet load.

Because investor-owned utilities are not preference customers they may only purchase energy which is surplus to the needs of Bonneville customers. Many do receive Wholesale Firm Capacity under the F-7 rate, however. DSI's receive Industrial Firm power because of their early long-term contracts with Bonneville, their ability to use energy which is not useable by utility customers, and because they can provide operating and system reserves.

The DSI power rate (IF-2) for demand and energy is the same as the preference customer (EC-8) demand and energy rate. The investor-owned utlities buy capacity and energy under the F-7 and H-6 rate schedules. The H-6 rate is higher than the EC-8 rate because it incorporates a "share the savings" concept. This concept is intended to bridge the large gap between the value of secondary energy and its actual costs. Its purpose is to distribute the substantial savings which accrue to secondary energy customers in an equitable manner among all of Bonneville's customers.

Further discussion of this topic can be found in the Administrator's Record of Decision for the 1979 Wholesale Power Rate Proposal, November 1979, page 55, and Revised Draft EIS at IV.A.2.e.

Letter No. 36, Comment No. 4

Refer to Comment No. 2 of this letter for a discussion of "melded" rates or rates based on "average cost pricing." Further discussion of average cost pricing can be found in the RDEIS on page III-28.

Alternative 4 cannot be implemented as the proposal because it is not within Bonneville's current authority.

Letter No. 36, Comment No. 5

Alternative 4 cannot be implemented as the proposal because it is not within Bonneville's current authority. (Refer also to Comment No. 2 of this letter.)

Letter No. 36, Comment No. 6

This comment does not address the EIS, rather, it relates to Bonneville practices in general.

For a discussion of marginal cost rates, see the next Comment response.

Letter No. 36, Comment No. 7

It is BPA's assessment that marginal cost rates with a revenue constraint do not meet the objectives of stability and continuity of rates. Furthermore, research is required to develop the most appropriate method for applying marginal cost principles to BPA 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 the state-of-the-art limitations.

For the 1979 power rate filing, Bonneville conducted a Long-Run Incremental Cost-of-Service Study. The results of this study are reflected in current rates.

The LRIC study revealed that costs of supplying energy are increasing at a faster rate than the costs of supplying capacity. The nonfirm energy rate and firm capacity rate produce revenue in excess of assigned costs. To reflect the results of the LRIC study, the excess revenues were applied as a credit against capacity costs only. Therefore, Bonneville incorporated the price signal that future energy costs will increase at a faster rate than future capacity costs. This adjustment, based on LRIC results, affected the firm power, industrial firm power, and modified firm power rate schedules.

Further discussion of this topic can be found in the Final EIS for the 1979 Wholesale Rate Increase, pages VI-4 to IV-9 as well as in BPA's evaluation of the NRDC Alternative Scenario (page C-36 and following) included as Attachment C).

BPA, as a wholesale power agency, does not directly control how its customers pass on power costs to end-users other than to see that retail rates are reasonable and nondiscriminatory.

Letter No. 36, Comment No. 8

See Comment No. 7 above.

Letter No. 36, Comment No. 9

Revisions to the text have been made to accommodate the comment.

Letter No. 36, Comment No. 10

The comment states that several plants available to serve regional loads had been omitted. The plants given as examples were Wyodak #2 and Valmy units 1 and 2. Generating plants such as these given, are not available to serve the regional loads used in the BPA analysis. Our analysis uses the West Group Area (WGA) loads and resources. The WGA does not cover other areas, including the eastern system of Pacific Power and Light Company (Wyodak #2 in Wyoming) or the service area of Idaho Power Company (Valmy units 1 and 2). Refer to response to Comment No. 14 of this same letter for additional information.

The text has been changed to accommodate the comments referencing the Jim Bridger #4 plant and the Skagit and Pebble Springs nuclear plants.

Letter No. 36, Comment No. 11

Revisions to the text have been made to accommodate the comment.

Letter No. 36, Comment No. 12

The first comment is that, "the cost from the Hanford Generating Project should be amended to include the costs incurred by the Department of Defense for operation of this facility. Since there is not currently a need for the byproducts of steam generation, this cost should be fully allocated to energy." The comment shows an apparent misunderstanding of the operation and financial procedures of the project, Hanford Generating Plant - New Production Reactor (HGP-NPR). The NPR is a dual purpose reactor, currently producing both plutonium for the Department of Energy (DOE) and byproduct steam. This steam is piped to the HGP for generation of electricity. The NPR is owned by DOE, and the HGP is owned by the Washington Public Power Supply System (WPPSS). DOE annually receives a negotiated amount for the steam delivered to the HGP, and WPPSS pays these charges. WPPSS also pays all costs associated with the HGP. If NPR was being operated solely for maximum steam production, the current method of operation would be different since the primary product now, is plutonium for DOE.

Another comment was that the plant factors of 75 percent which were used in calculating unit energy costs from Centralia and Trojan were too high. The subject of plant factor value has been intensely discussed both within and outside the electric utilities. Because of this controversy, we decided to use values set by the plant owner, or owners, rather than arbitrarily set a value of our own. The cost at a different capacity factor can be determined by a simple calculation. For plants which do not have a value set by the owner, we have used the standard planning value set by the Pacific Northwest Utilities Conference Committee (PNUCC), a regional planning group. Additionally, one of the causes of the low actual capacity factors at Trojan has been the displacement of plant operation by using inexpensive secondary hydro energy. This makes the unit energy cost at Trojan higher, but results in a lower total cost for the year, a benefit for customers.

In response to the comments requesting notes about higher unit energy costs at Centralia and Trojan, refer to Table IV-5, which has been updated.

Letter No. 36, Comment No. 13

Revisions to the text have been made to accommodate the comment.

Letter No. 36, Comment No. 14

In this EIS, BPA has included thermal plant energy costs only on those plants in which BPA acquires all or a part of the power. Those with no BPA participation include: Jim Bridger No. 4, Boardman, Skagit, and Pebble Springs.

Letter No. 36, Comment No. 15

BPA regards net-billed plant costs as an obligation in its financial statements but, since these are not Federally constructed projects, Bonneville does not include them in a listing of Federal plants. We are unaware of any participant denying its contractual obligations regarding these projects.

LETTER NO. 37

Lane County Audubon Society

Letter No. 37, Comment No. 1

Bonneville is currently exploring the use of rate incentives to encourage conservation.

Letter No. 37, Comment No. 2

The comment seems to infer that the data given in the Electric Power Research Institute (EPRI) Journal (Vol. 5, No. 3, April 1980) conflicts with the RDEIS information on potential compressed air storage and potential battery storage. A general statement about the method of storing electrical energy in the Pacific Northwest (PNW) is that it currently is in the form of water stored in reservoirs on rivers. Electrical energy from another source can be stored by reducing the generation at a hydroelectric plant and storing the water which would have been used. This procedure will be used until the storage capacity and hydrogeneration capability have been committed. With this storage system available, no other storage systems have been considered except for studies on pumped-storage (P-S). The P-S system seems to be the next most likely alternate because of the current technology and the many apparently suitable sites in the Pacific Northwest.

In reference to the comments on compressed air storage, the comment states that EPRI indicates the capital costs would be less than $300 per kW and the annual costs would be $5 per kW . We presume the comment is referring to the chart on page 10 of the EPRI Journal, and if so, it is in error. The approximately $300 per kW is the base cost for a unit with no storage capability, and the $5 per kWh is the capital cost increase with each additional kilowatthour of daily storage capability. In the Pacific Northwest, an 8-10 hour storage capability is considered necessary. From the chart, the capital cost would be about $320 per kW, with 8 hours storage capability. An annual cost of $5 per kWh would be completely unacceptable, being 5,000 mills per kWh. This compares to about 40 mills per kWh for resources currently being considered. Our RDEIS capital cost estimate is about $300 per kW, very close to the EPRI value.

The comment also states that the EPRI capital costs for batteries ranged from $80-700 per kW instead of the figures in our Table IV-25. In Table IV-25 of the RDEIS, we gave capital costs of four types of batteries, including nickel-cadmium (N-C), which we stated only as a reference, since its cost is so high. Our range is $150-500 per kW, not including the $1,500 per kW for N-C batteries. Considering the speculative nature of cost estimates for advanced batteries, we believe our values are comparable.

All storage systems produce less energy than they receive. These losses can be one-third or even more. The present Pacific Northwest hydro storage system is an exception, being 90 to 100 percent efficient.

Letter No. 37, Comment No. 3

In accordance with Bonneville's environmental procedures, all States affected by a major BPA action receive both threatened and endangered species consideration. This includes both Federal and State listings, and species being proposed for listing.

Letter No. 37, Comment No. 4

Bonneville's 1979 wholesale firm power rate, reserve power rate, industrial firm power rate, and modified firm power rate contain demand charges that vary according to the time-of-day in which demand is purchased. Time-of-day pricing is also reflected in the 1979 nonfirm energy rate. Bonneville has explored baseline power rates in the 1979 rate filing and is continuing to study various forms of baseline rates.

LETTER NO. 38

U.S. Department of Agriculture; Soil Conservation Service

No response required.

LETTER NO. 39

Oregon Voice of Energy

No response required.

LETTER NO. 40

Northern Plains Resource Council

Letter No. 40, Comment No. 1

As stated in their February 1, 1978 testimony on the original DEIS and as reflected in this comment letter on the Revised Draft EIS, NPRC concerns revolve around three issues: State rights, specifically as it applies to siting authority for coal development in Montana; a BPA proposal for resource development or a likely scenario favored by BPA; and finally recognition of the need for conservation.

The above concerns are similar to those expressed by the State of Montana which are addressed in response to Letter No. 45. The reviewer is referred to those responses for additional information.

The basic point that needs to be made here is that BPA is not proposing any type of resource development, coal or otherwise. In fact, the only "resource" Bonneville is currently advocating is conservation. It must be remembered that although the Hydro-Thermal Power Program (HTPP) was an ambitious program based upon the development of conventional generation resources, Bonneville's participation in that program was predicated upon its ability to provide for "net-billing." In this regard, Bonneville "had something to offer" the utilities. It was this net-billing capability, specifically, that was the basis for BPA's involvement in coordinating the HTPP. As explained in the RDEIS, this net-billing capability was quickly exhausted due to increasing costs of new thermal development. As a consequence, BPA does not have any more net-billing capability or "direct purchase authority," and is no longer involved in a program to develop regional resources, including coal. However, in light of the political and technical difficulties associated with development of nuclear energy, the Administration's advocacy of coal development, the proven coal resources in the State of Montana, forecasted regional deficits, and the uncertainties associated with unconventional resource development, it is not hard to understand the interest the region's utilities have in the coal resources located in Montana and Wyoming. Again, it is the utilities and not BPA seeking to develop these resources.

A very recent example of this is the Creston coal-fired plant which plans on utilizing Wyoming coal. This plant is planned for and sponsored by Washington Water Power with no BPA involvement.

The point simply is, there is no regional power program and without "something to offer," or the authorities to formulate a regional power program, BPA is not able to coordinate the development of a program "equivalent" to HTPP.

Consequently, in conjunction with BPA's Notices of Insufficiency, the region's utilities are beginning to take steps they feel necessary to resolve their own particular energy problems. Naturally, those utilities with access to coal resources appear to be considering development of those resources.

Finally, as stated in the RDEIS on pages I-9 (State Control of Sites), III-13 (Load Forecasting), III-16 (BPA Cooperative Activities), and on III-32 (State and Local Government), BPA does not plan to disregard States' rights.

In fact, under the proposal it is clearly and specifically stated that, "State and local siting and licensing criteria for the construction of new resources would be unaffected by either BPA or regional power entity action."

Under Alternative 3 which reflects the provisions of Senate Bill 885, provisions for State involvement and coordination are explicit, including the provision that, "State and local government siting and regulatory authority over utilities would remain unchanged."

Letter No. 40, Comment No. 2

BPA has an obligation as a Federal bureau to carry out Federal programs, moving within the directions and constraints of the US Constitution. Pursuant to Article VI, Clause II of the United States Consitiution, laws enacted by Congress are the supreme law of the United States. State laws which are in conflict with or which interfere with Federal law or Federal programs must give way. The application of this concept is called the "supremacy doctrine." Accordingly, BPA as a Federal bureau handling Federal programs may not submit the decision regarding a Federal program over to any State. However, Bonneville has, and will continue to, coordinate its activities with those of the States, and will continue to notify and advise the States of its activities as required by OMB Circular A-95.

(Also see Comment No. 1 of this letter for additional information.)

LETTER NO. 41

Mr. Eugene Stuckle

No response required.

LETTER NO. 42

State of Washington; Office of Program Research

Letter No. 42, Comment No. 1

Section IV.E, entitled Summary and Comparison of Impacts of the Proposal and Alternatives, was developed to address this need.

Letter No. 42, Comment No. 2

The requested change was made in the summary.

Letter No. 42, Comment No. 3

The 1,300 MW firm peaking capacity figure given for solar central station in Table IV-33 of the RDEIS is correct as written. It represents 10 percent of the 13,000 MW installed capacity given in Footnote 1 of Table IV-32.

LETTER NO. 43

Montana State Clearinghouse
Office of Budget and Program Planning

No response required.

LETTER NO. 44

Hanford Energy Center Program

Letter No. 44, Comment No. 1

The discussion cited on page I-23 is an attempt to paraphrase or summarize the comments received on the original Draft EIS. The need to be able to distinguish between theoretical potentials and achievable potentials is still valid. The reason this distinction is not presented in the Role EIS is because the analytical basis for making this distinction, in terms of the end-use data required, has not been completed. However, especially in the last couple of years, considerable progress has been made in compiling data necessary to the completion of this task.

The second paragraph on page IV-194 of the RDEIS goes on to say that, "This assumption is made without consideration of economic, technical, or institutional factors which may inhibit full development, but remains consistent with the concept that these scenarios are extreme cases of reliance on these technologies."

Letter No. 44, Comment No. 2

Clarification was made in the summary.

Letter No. 44, Comment No. 3

As defined on page IV-191 of the RDEIS, the scenarios are considered "worst case only in the sense that they represent extremes of reliance on a given type of technology."

Letter No. 44, Comment No. 4

The emphasis given is felt appropriate.

Letter No. 44, Comment No. 5

The figures given for installed capacity of solar central station and large-scale wind in Table IV-32 do appear high, and indeed are not supported by earlier discussions of these resources. Their use, however, is to develop a scenario for 100 percent renewable resources. This scenario does not represent what is realistic, but rather establishes an extreme development scenario which can then be compared to other scenarios.

Letter No. 44, Comment No. 6

See Comment No. 5 of this letter.

Letter No. 44, Comment No. 7

The statement has been deleted. However, the following paragraph in Section IV.B.3.c, does explain that the basis for these assumptions is consistent with the "worst-case" approach.

Letter No. 44, Comment No. 8

Revisions to the text have been made to accommodate the comment.

Letter No. 44, Comment No. 9

The air emission figures in Table IV-39 of the RDEIS are not limited to the conversion process, but include emissions from the entire generation trajectory. The Draft EIS table on nuclear residuals (V-55), has been incorporated into the text to show where these emissions occur.

Letter No. 44, Comment No. 10

Both Tables V-54 and V-55 of the Draft Role EIS have been included in the Final EIS to clarify this. The reason these numbers seem unlikely is because they include the entire fuel cycle. It is true that during the conversion stage a coal plant generates more solid waste than a nuclear plant. However, due to the differences between uranium and coal deposits, extraction of the uranium ore disturbs more nonfuel material.

LETTER NO. 45

State of Montana; Office of the Governor

INTRODUCTION TO COMMENTS FROM THE STATE OF MONTANA

As indicated in the State of Montana cover letter, comments were submitted and prepared in response to the original Role EIS issued in 1977 and were not directed toward the Revised Draft EIS.

Given the fact that the original draft was a much different document and that it was a 3,200-page, 5-volume document compared to the single volume RDEIS, the applicability of Montana's comments to the RDEIS may be difficult to establish. This is especially a problem for many of the State's comments which were directed at specific volumes of the Draft EIS that are not represented in the Revised Draft EIS.

In light of the above, what has been attempted here is to abstract some of the State's "generic" concerns as well as specific policy questions and to respond to them in terms of the current regional situation.

Letter No. 45, Comment No. 1

BPA fully recognizes the role of the States and the public in power system planning. This recognition is evidenced by the discrete provision for the public and the State and local governments included in Chapter III under each alternative and the proposal.

Letter No. 45, Comment No. 2

The proposal and alternatives considered in the EIS are designed to address, "differing levels of regional cooperation and coordination or alternative approaches to the one-utility concept. . ." (page i, RDEIS). In determining the scope of this EIS certain things were taken as given, including reliability and critical period planning. The basic reason for this is that neither of these areas is affected by the proposal or alternatives. Nevertheless, for the purpose of information, a discussion of these topics was included in Attachment A of the RDEIS.

Letter No. 45, Comment No. 3

The RDEIS which obviously represents a complete reorganization and reformulation of the original Draft EIS, was prepared specifically in response to this and similar comments regarding its length and organization. Accordingly, Bonneville feels that it has been more than responsive in accommodating this concern and in furthering the purposes of NEPA by sending the document out for an additional public and agency review.

Letter No. 45, Comment No. 4

The RDEIS, consisting of less than 500 pages, represents a substantial reduction from the original 3,200 pages. However, anyone having prepared an EIS is familiar with the now classic dilemma posed by the need to keep EIS's "succinct" and simple (even though the subject matter is complex) and at the same time respond to demands to add additional information important to a particular point of view.

One last point is that the outline and structure of the original Draft EIS were reviewed and approved by the CEQ prior to the preparation of the draft document.

(See also, Letter No. 50, Comment No. 3.)

Letter No. 45, Comment No. 5

The description of the affected environment takes up a total of 6 pages. By comparison, a total of 334 pages were devoted to the discussion of environmental consequences.

Letter No. 45, Comment No. 6

Again, the bulk of the RDEIS is Chapter IV which is an anlysis of the environmental consequences associated with the proposal and alternatives.

Letter No. 45, Comment No. 7

The point made in the Draft EIS and again in the RDEIS was that increased cooperation/coordination enhances regional or system efficiencies. This in turn minimizes system requirements by lessening the need for new facilities which avoids or mitigates impacts to the environment.

Letter No. 45, Comment No. 8

Following the provisions of the new CEQ regulations, a discussion of mitigating measures has been incorporated into the discussion of the proposal and environmental consequences. However, since Bonneville is not proposing to "lessen public accountability" or to develop "large nuclear and coal-fired plants to the exclusion of alternative energy development," discussions to mitigate these will not be found in the RDEIS.

A discussion of the influence of the existing grid was included in Attachment A of the RDEIS.

An evaluation of BPA's ability to effect regional resource development was included as Section IV.C of the RDEIS.

Letter No. 45, Comment No. 9

BPA is not proposing the development of any resource, "mine mouth" included.

The cost of melded hydropower is not regarded as a determining factor in population growth any more than recent cost increases (approximately 150 percent) have been a factor in offsetting population growth.

Letter No. 45, Comment No. 10

In terms of the RDEIS, Volumes No. 1 and 2 of the original Draft EIS no longer exist. Reliability which was discussed in Attachment A of the RDEIS is not affected by the proposal and alternatives and was, therefore, considered outside the scope of this EIS.

Letter No. 45, Comment No. 11

The geographical boundary of the BPA service area did not fix the scope of the EIS. As stated on page i and IV-1, the RDEIS considers the impacts of the system as a whole, including "facilities built to serve regional electrical firm loads, whether or not these facilities are located within BPA's geographical service area."

Letter No. 45, Comment No. 12

BPA does not see an inconsistency between the widest possible use and the need for conservation. Basically, by obtaining greater efficiency through conservation Bonneville will be able to make Federal power available to a greater number.

Letter No. 45, Comment No. 13

These contracts are not inconsistent with sound conservation policy. The rate schedule for these contracts is the EC-6 schedule which included both a demand charge and an energy charge. These customers pay a demand charge up to their demand limit and an energy charge for the energy consumed.

Letter No. 45, Comment No. 14

See response to next comment.

Letter No. 45, Comment No. 15

Bonneville is presently studying rates which encourage conservation and other rate designs most applicable to the Bonneville system. BPA is committed to encouraging conservation, although the conservation rate alternatives available to Bonneville are somewhat dependent upon existing authority and pending legislation.

The discussion on time differentiation of rates in the Rate EIS, pages VI-9 to VI-29, is an example of current rate design which promotes conservation through load management.

Further discussion of conservation rates can be found in the EIS for the 1979 Wholesale Rate Increase, October 1979, on pages VI-39 to VI-47.

Letter No. 45, Comment No. 16

Bonneville is unable to present information on the specific rate-making techniques which would be used under the Alternatives presented. Only an analysis of the general directions which would be taken can and have been provided.

It is beyond the scope of the Role EIS to delineate specific rate-making techniques for all the Alternatives presented. Bonneville is presenting an evaluation of various mechanisms illustrative of BPA's function or role in regional energy activities. Bonneville is not proposing, nor can it identify and evaluate, any existing discrete program to solve the energy shortage in the region.

Letter No. 45, Comment No. 17

The references cited in Comment 3 Conservation of this letter apply specifically to portions of the original Draft EIS and not the RDEIS.

Suffice it to say that Bonneville has included a conservation policy in its proposal (Chapter III.B) and is now involved in a series of pilot conservation programs which are being implemented under this policy. Consistent with this policy, Bonneville recognizes conservation as a resource with its cost-effectiveness measured against the marginal cost of new generation facilities.

Letter No. 45, Comment No. 18

A discussion of potential regional resources was included in Chapter IV.B.2 of the RDEIS. Twenty-one different resource types, renewable and nonrenewable, conventional and unconventional, were included in this evaluation. In addition to a brief description on the technology there was a description of the resource's potential, cost, and impacts. However, because there is no proposal for resource selection in the Role EIS, this evaluation is only intended to present a generic appreciation of the different resource types. Accordingly, this material is not intended to be a definitive examination or a "rigorous analysis" used for a basis in making resource selections.

Letter No. 45, Comment No. 19

Bonneville's wholesale power rate schedules contain both demand and energy charges. Whenever a demand charge is included as part of a power rate, high load factor customers will benefit because they take power at a uniform rate and, therefore, minimize their peak demand and average cost of power. If Bonneville did not include a demand charge in its rate, there would be no incentive for its customers to minimize their demand and Bonneville's resources would be utilized less efficiently.

An average cost-of-service analysis prepared for the 1979 wholesale rate filing revealed that power costs are currently nearly equally divided between capacity and energy. A long-run incremental cost (LRIC) study was also conducted for the 1979 filing which focused on incremental costs incurred to meet load growth requirements. The results of the LRIC study indicated that the cost of adding new energy resources is increasing faster than the cost of adding capacity. Bonneville based its 1979 rates on average costs for capacity and energy derived from the cost-of-service analysis, but modified them to reflect results of its long-run incremental cost study. The modifications were made by lowering firm power peak and secondary peak period capacity charges and eliminating firm power capacity charges during the night-time hours. As a result, the revenue burden was significantly shifted from the capacity rate to the energy rate. High load factor customers consequently experienced a larger percentage increase in purchased power costs as a result of Bonneville's 1979 rate increase than did low factor customers.

Presently, BPA serves about 3,600 MW of DSI load. The top quartile (first 1/4) is interruptible and considered nonfirm energy. The second quartile (or 1/4) can be restricted for energy reserve. This second quartile of DSI load is ideal for a reserve in that there are few delivery points and each has a relatively large block of power which can be restricted by BPA load-control devices. The contractual arrangements for this second quartile give it the highest priority of service for BPA secondary energy. Thus, while the second quartile is restrictable, it is only restrictable just prior to restriction of firm loads. The DSI load serves BPA in the following ways:

1. Plant Delay Reserves - BPA has the right to restrict service to the second quartile if the initial operation of certain large generating resources is delayed or if the initial performance of such resources does not meet anticipated levels. Because BPA has this right to restrict, Bonneville does not need to maintain as much power in idle reserve and can therefore serve a larger firm load.

2. Forced Outage Stability - The DSI load is also restrictable to insure stability of the Federal system or when a forced outage suspends or interrupts the operation of a Federal system facility. BPA has protective relays, including underfrequency relaying, on the industrial ties. There are, however, limitations to the restrictions. For example, 25 percent of the contract demand can be restricted for up to 1,500 hours per year, and 50 percent can be restricted for not more than 2 hours in a day nor more than 100 hours in a year. Thus, the length of the restriction varies inversely with the magnitude of the restriction. At best, this type of reserve is useful only for multiple short-term outages.

Letter No. 45, Comment No. 20

The ability to interrupt DSI load exceeds 25 percent when, as now, there is a delay in the commercial operation of new generating units. DSI load is also interruptible for forced outage and stability problems on the Bonneville system.

A comprehensive discussion of DSIs and reserves provided through interruption rights is presented in the Revised Draft Role EIS on pages IV-69 to IV-82. The determination of the amount of credit that should be given to the DSIs for Bonneville's rights to interrupt their load is included in the EIS for the 1979 Wholesale Rate Increase on pages VI-29 to VI-32.

Bonneville is presently conducting an indepth study of system reserves provided by the DSIs and their value.

When BPA must restrict DSI loads during drought or low water conditions in order to protect firm loads, BPA acts as purchasing agent for the DSI. Occasionally outside regions will have surplus available when the PNW region is in a drought condition. Then, the DSIs can continue to operate when the region cannot provide sufficient power for them. The cost of this power is carried by the DSIs. If a greater portion of their load was considered firm, that cost would have to be paid by BPA or additional generation installed and reflected in higher rates.

Letter No. 45, Comment No. 21

The RDEIS presents a single discussion of system reliability which does not arbitrarily defend existing reliability criteria. It needs to be pointed out that to date, the reliability standards have been based more upon engineering judgment than numerical analyses.

However, for several years now Bonneville has been collecting and analyzing outage data on the transmission and generation system for use in assessing the existing reliability criteria. Additionally, BPA is in the process of developing computer software for the automated evaluation of the reliability of the region's bulk power systems (generation and transmission). This computer capability will be utilized in the development of a generation expansion model used in determining the best generation mix including load management, conservation, renewable resources, and conventional resources. Reliability will be a factor in these evaluations.

In conclusion, Bonneville's position with regard to the existing reliability criteria and the current level of reliability is hardly static. With these new analytical capabilities Bonneville will be able to continually evaluate the system reliability to determine the optimal level considering engineering, economic, and environmental factors.

Letter No. 45, Comment No. 22

This comment speaks to two issues, i.e., forecasting and pricing.

With regard to forecasting, it is true that the historical approach to forecasting has been one based upon trends. However, increasingly within the region there is a movement toward an "econometric" approach. This modeling approach examines components or variables that influence energy consumption, for example, population, income, employment, and the cost of energy. Based upon the relationship of these variables a forecast is developed. (It should be remembered that regardless of the planning methodology or forecast technology utilized all are prognostications subject to error.) Currently, PGE and PP&L use an econometric approach, and their requirements are reflected in the West Group Forecast. As for BPA, we also utilize an econometric forecast for use by the Pacific Northwest Utilities Conference Committee in checking the reasonableness of the region's West Group Forecast.

Bonneville does recognize the theoretical basis for marginal cost pricing, particularly as it applies to new resources. Bonneville has taken the position that when evaluating cost-effectiveness of conservation or any new resource it should be compared against the marginal costs, not against average system costs. With regard to the wholesale application of marginal cost pricing, several things should be kept in mind. Most significantly, perhaps, is the political/public opposition that exists toward marginal cost pricing. This resistance is reflected in the fact that with the exception of a few limited experimental situations, no utility in the U.S. currently employs marginal cost pricing. The hardships and resistance to marginal cost pricing are especially significant in the Pacific Northwest because although our marginal costs are the same as nationally, our hydro costs are so low that the differential is especially large (as much as five times over average cost pricing at the retail level). No less of a problem, would be the tremendous excess revenues generated if marginal cost pricing were applied in the region.

For additional discussion on the advantages and disadvantages of marginal cost pricing and how it applies to BPA, refer to BPA's Rate EIS.

Letter No. 45, Comment No. 23

Although the approach taken in the original DEIS was to limit the discussion of impacts to those occurring in the BPA service area this is not the case in the RDEIS.

As indicated on page i of the summary the EIS examines the impacts of Federal and non-Federal facilities built to serve regional loads, whether or not these facilities are located within the service area. Consequently, the discussion of transmission and generation facilities in IV.A.3 and IV.A.1 includes those located in the State of Montana.

Letter No. 45, Comment No. 24

As discussed in this letter, Comment No. 11, the RDEIS did not exclude extraregional impacts by limiting the scope of the EIS to the Pacific Northwest. Resources located outside the BPA service area and those designed to serve loads in the Pacific Northwest were addressed. Consequently, the Jim Bridger plants and Cosltrip Units 1 and 2 were included in Sections IV.A.1.a.2, IV.A.1.b.2, and IV.A.3.

Letter No. 45, Comment No. 25

As mentioned above, the RDEIS specifically states that the siting authorities of States will not be affected by the proposal and alternatives. In fact, Alternative 3 provides for a "statutorily defined planning process" (page III-53 of the RDEIS) which includes participation by the governors, local governments, utility and industry representatives, and the public. Similar provisions exist for each alternative and the proposal.

Letter No. 45, Comment No. 26

The analysis in the RDEIS has been expanded in Alternatives 3 and 4 to accommodate the essence of the "Jackson" and "Weaver" bills. Both of these bills are under active consideration.

The scope of the RDEIS has also been expanded to cover impacts outside the BPA service area. Future transmission requirements including those to integrate generation built outside the region which are intended to serve Northwest loads have been addressed in Chapter IV.A.3.

Letter No. 45, Comment No. 27

We agree, when determining the effectiveness of any resource, transmission cost should be incorporated into the economic analysis. However, a feasibility analysis which should also be part of any resource selection, would consider noneconomic criteria including social/political constraints. Again, the RDEIS has been expanded to cover the impacts that would occur in the State of Montana.

Letter No. 45, Comment No. 28

As mentioned above, the proposal and alternatives each address the issue of State siting authority. As provided, there will be no effect on States' authorities in these areas.

Letter No. 45, Comment No. 29

As discussed under the preferred or "ranking alternative," (Alternative 3) and, "in determining whether a conservation measure or other resource is cost-effective, BPA would compare the cost of the proposed resource to the lowest cost alternative resource which could feasibly serve the projected load and could be available for acquisition" (page III-55 of the RDEIS).

In making these determinations, BPA would give priority first to conservation, second to renewable resources, and third to conventional resources, giving greater priority to high efficiency resources.

In implementing the above, BPA would be following a regional plan developed through a "statutorily defined planning process."

Letter No. 45, Comment No. 30

As indicated in the preceding response, a priority would be placed upon conservation under the preferred alternative.

Letter No. 45, Comment No. 31

See response to Letter No. 32, Comment No. 1.

Letter No. 45, Comment No. 32

We agree. As reflected in Chapter III, adequate provisions have been made for State and public involvement and regional power planning for the proposal and each alternative.

LETTER NO. 46

California Energy Commission

Letter No. 46, Comment No. 1

In addition to the reference cited on inter-regional transaction affects (page IV-267), the impacts on secondary sales are discussed further in Chapter IV.A.2.c.

Letter No. 46, Comment No. 2

The purpose of the Role EIS is a limited one. Its objective is to evaluate the environmental impacts associated with the operation and development of the regional power system under various levels of regional cooperation and coordination. Although national problems are of concern to Bonneville and effect policy decisions, they are not within the scope of the EIS.

Changing oil prices and other factors which affect energy sales to California have been studied and considered since 1977. The Administrators Record of Decision for the 1979 Wholesale Power Rate proposal, published November 1979, includes a discussion of energy sales to California under the H-6 rate on pages 55 to 63. A more complete discussion of impacts to California from rate increase can be found in the Bonneville Staff Evaluation of the Official Record, published July 1979, on pages 119 to 151.

Letter No. 46, Comment No. 3

Revisions to the text have been made to accommodate the comment.

LETTER NO. 47

U.S. Department of Commerce; Assistant Secretary for Productivity, Technology, and Innovation

Letter No. 47, Comment No. 1

Chapter III has been revised to reflect the recent change in the region's volcanic activity. Otherwise, the characterization of the region's weather is felt to be representative. Accordingly, no other changes were made in the text.

LETTER NO. 48

U.S. Department of the Army; North Pacific Division,
Corps of Engineers

Letter No. 48, Comment No. 1

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 2

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 3

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 4

The discussion referenced on page I-15 was not intended to recount all previous water resource studies relative to hydropower. The only point being made on page I-15 is that the concept of hydro/thermal coordination goes back to the early 1920's.

Letter No. 48, Comment No. 5

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 6

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 7

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 8

Refer to Letter No. 21, Comment No. 7 and text changes made to Chapter IV.A.1.a.

Letter No. 48, Comment No. 9

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 10

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 11

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 12

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 13

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 14

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 15

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 16

Revisions to the text have been made to accommodate the comment.

Letter No. 48, Comment No. 17

Revisions to the text have been made to accommodate the comment.

LETTER NO. 49

Modern Energy Systems, Inc.

Letter No. 49, Comment No. 1

Expanding the scope of energy transmission to include nonelectric technologies is somewhat beyond the purview of the Bonneville Power Administration.

Other nonelectric technologies to be developed in the decades ahead will, in many instances, require extended research, development, and demonstration before commercial feasibility.

Letter No. 49, Comment No. 2

The PNUCC Econometric Model of Electric Sales Forecast for the West Group Area includes a provision for the impact of electric vehicles on future power demands in the region. Concerning future impacts that electric powered autos may have on utility loads, a study by Mathtec Inc., for the Electric Power Research Institute in 1978 projected that by the year 2000 approximately 8 percent or about 12 million of the 141 million passenger vehicles on U.S. roads would be electric powered.

However, the impact on utility loads, even in large metropolitan areas, was projected to be negligible, amounting to 1 percent or less of total peak demand and electric energy consumption. Even under the most optimistic assumptions, electric passenger vehicles are not expected to add significantly to electric utility loads before the year 2000. Moreover, the small changes in demand that do occur will tend to increase utility plant utilization because the major portion of the recharging load is anticipated to be at night during periods of low demand.

Letter No. 49, Comment No. 3

Fuel cells and their development are receiving special attention at BPA, along with other emerging storage and site generation technologies. Currently, BPA is undertaking a comprehensive study of fuel cell applications and the role that fuel cells might play in the Pacific Northwest System.

Letter No. 49, Comment No. 4

BPA does not have any jurisdiction in the areas suggested. Given the fact that this EIS deals with alternative electrical power planning processes, these concerns are clearly outside the scope of this EIS.

Letter No. 49, Comment No. 5

The reported rail cost estimates are the result of considerable study of existing rail transportation systems in the Pacific Northwest.

No equivalent cost estimates are presently available for coal slurry pipelines since no pipelines exist to the Pacific Northwest and proposed pipeline routes are still speculative. Such costs may not be available until future detailed studies of specific pipeline proposals generate sufficient data.

Letter No. 49, Comment No. 6

In the referenced discussion, the water requirements of existing coal-water slurry pipelines can be readily presented. However, coal slurry pipelines using methanol, coal oil, or any other carrier fluid, do not presently exist and will presumably be the topic of extensive future RD&D. Obviously, the water requirements (referenced in the comment) result from the production of synthetic carrier fuels from coal and are process specific. As such, they are not readily available for presentation.

Letter No. 49, Comment No. 7

While EPA does not currently restrict the emissions of aldehydes, they are concerned about the elevated levels of aldehyde and NOx pollutants from alcohols and alcohol extended fuels.

The process described of:

$$\text{coal gasification} \dashrightarrow H_2 + CO \dashrightarrow CH_4OH \dashrightarrow H_2 \dashrightarrow$$

power has not been established as viable at this time, nor the overall efficiency determined.

The amount of water required to produce methanol from coal would be in excess of the 1-1/2 to 3 pounds of water per pound of coal processed since coal gasification is the first step in the process to produce H_2 and CO which are then catalytically converted to methanol.

LETTER NO. 50

U.S. Department of Commerce; National Oceanic and Atmospheric Administration; National Marine Fisheries Service

Letter No. 50, Comment No. 1

We can appreciate that in reviewing EISs, the National Marine Fishery Service normally looks for project specific impacts as they relate to fisheries. However, since the Role EIS is a programatic EIS examing institutional alternatives, project specific impacts are not involved. Project specific impacts would naturally be examined if, for example, a regional power program was formulated.

To the extent they could be identified, relationships and impacts to fishery resources have been addressed under nonpower considerations.

As specified in the document, the proposal does not involve any changes in operation including those to the river system.

Since no programs are proposed, no conflicts are expected with State and local plans. Furthermore, specific provisions for accommodating State and local plans in the future have been included in the proposal and each alternative.

In conclusion, BPA believes that the Role EIS is adequately detailed to make an informed choice among the alternatives at hand. Certainly the Role EIS lacks the detail to inaugurate new programs and projects. But these are not now being proposed and are not presently being decided upon. The Role EIS does present known information on the foreseeable environmental consequences of the five alternatives to the one-utility concept. The decision to be made is a selection among the five alternatives. The Role EIS presents enough information to make an informed decision among them.

Letter No. 50, Comment No. 2

Refer to BPA's Draft Role EIS, Appendix A, Chapter III. The bibliography for that section, found on pages III-201 through III-211, stands as the documentation and scientific support for this discussion. However, we recognize that additional data has been developed and new studies have been undertaken since the Draft Role EIS was published in July 1977. In revising the fisheries discussion of the Revised Draft EIS (Chapter IV.A.1.a., we have included additional, more recent publications as footnotes to the section.

Letter No. 50, Comment No. 3

It is our position that a good deal was done to accommodate public agency's review of the EIS.

To begin with, the major criticism of the original 5 volume draft was its length and complexity. Primarily in response to this comment, the EIS was completely rewritten as a single volume EIS. The RDEIS more clearly focused on the issues and provided a discrete comparison of the proposals and alternatives. Additionally, the RDEIS was distributed for another public agency review. In the case of the original Draft EIS and the Revised Draft EIS, the review periods were substantially more than required.

In addition to these rather significant measures, a 38-page overview chapter (Chapter I) was included in the DEIS solely for purposes of orientation and explanation. It was also felt that the numerous workshops and information seminars held in conjunction with the original Draft EIS provided the public and agencies with an appreciation for and a familiarity with, the issues involved.

(Also refer to Letter No. 45, Comment No. 4.)

Letter No. 50, Comment No. 4

We have examined the Fish and Wildlife Coordination Act (16 U.S.C. 661 et seq.) closely without finding authority for its application to those functions for which Bonneville Power Administration has responsibility. BPA is neither mandated nor authorized to undertake responsibilities or assume a specific role or act in derogation of the Bonneville Project Act under the FWCA. Section 661 authorizes the Secretary of Interior to undertake certain tasks to accomplish the several purposes including recognition of the contribution of wildlife resources to the Nation and provision that wildlife consideration receive equal consideration with other features of water resource development programs. Except as to the Secretary, the section is not self-executing, but by its terms relies for accomplishment of purpose upon subsequent sections of the Act, which are directive to construction agencies, i.e., the U.S. Army Corps of Engineers and the Water and Power Resources Service.

BPA, as a power marketing agency of the United States Department of Energy, is responsible for the marketing of electricity from existing Federal dams and other resources of the Federal Columbia River Power System. Pursuant to a long-term coordination agreement negotiated with the Federal construction agencies and non-Federal generating utilities, Bonneville participates with the Corps of Engineers and the Water and Power Resources Service in establishing operational plans each year whereby a single ownership is simulated to assure optimal and coordinated management of the resources and monthly levels are established for each reservoir. Within constraints established by the Corps of Engineers and the Water and Power Resources Service, Bonneville develops 30-day plans, two 3-day plans, and finally hourly plans to determine where and when generation or flow will be used to meet load requirements. However, the Corps of Engineers and the Water and Power Resources Service have responsibility for operation of the projects and only those agencies may modify the operational constraints which they have established.

Further Congressional action would be required to authorize and direct the operational modifications and compensatory measures you purpose for consideration. Proposals for such additional legislation are pending in Congress at this time, but inclusion of such possible authorities or mandates in the RDEIS are premature before Congress acts.

Letter No. 50, Comment No. 5

We appreciate the concern expressed. As explained in the RDEIS, one reason for Alternatives 3 and 4 being designated the environmentally preferable alternatives was their ability to accommodate nonpower concerns, including fish.

Letter No. 50, Comment No. 6

This issue was specifically addressed on page I-20 of the RDEIS.

Letter No. 50, Comment No. 7

Refer to Letter No. 21, Comment No. 1 and Letter No. 50, Comment No. 4.

Letter No. 50, Comment No. 8

Refer to Letter No. 21, Comment No. 1 and Letter No. 50, Comment No. 4.

Letter No. 50, Comment No. 9

All the alternatives presented in the RDEIS, including the "ranking alternative," present alternative ways of applying the one utility concept. As explained in the document, these alternatives do not present program proposals for BPA.

On page I-20 of the RDEIS, when programs are formulated and depending upon the actual involvement/responsibilities BPA has for these programs, there will be environmental analyses performed. These analyses would involve an examination of impacts specific to fish.

(Refer also to Letter No. 21, Comment No. 1.)

Letter No. 50, Comment No. 10

Not knowing what future resource (generation) mix will ultimately develop in the Pacific Northwest, the "worst case" analyses found in the RDEIS were designed to represent the extremes in terms of the region's reliance upon a given type of resource. As such, the scenarios are not designed around the issue of fishery impacts.

Letter No. 50, Comment No. 11

It is the EIS and not BPA's role that is characterized as "institutional." The reason for this is because the EIS examines the interrelationships of regional entities under the different alternatives.

BPA's influence in the area of energy development in the Northwest is discussed in Chapter IV under, "BPA's Ability to Affect the Regional Resource Mix."

The institutional provisions of Northwest Power Bill are discussed in the RDEIS under Alternative 3. However, it is important to note that the major impact associated with the Northwest Power Bill is not its institutional provisions but those provisions related to the development of a regional power program which would be formulated if this bill was enacted. However, no such power program exists in the Northwest today.

Letter No. 50, Comment No. 12

Customer services, including load factoring and forced outage reserves, are provided as long as the operational constraints of the Federal dams do not preclude their sale. These operational constraints have incorporated into them environmental restraints established by the U.S. Army Corps of Engineers and the Water and Power Resource Service, many of which are directed toward protection of the Columbia River fishery. Fishery related constraints are not incorporated into load factoring and forced outage reserves per se. Load factoring and forced outage reserves are customer services that are contractually provided on a nondiscriminatory basis as long as operational constraints are not violated. For the reason given on page IV-334 of the RDEIS, it is anticipated that if and when the region's power production is further optimized under the one-utility (Alternative 3 & 4) concept, it will indeed be easier to incorporate fishery concerns into river operation than is presently possible.

Letter No. 50, Comment No. 13

In the second paragraph of the discussion on Load Forecasting (page III-13 of the RDEIS), reference is made to the data base prepared under the auspices of the PNUCC. Beginning with the 1980 West Group Forecast and Assured Operating Plan, a deduction from assured power resources has been taken reflecting water provided for fish spills during the spring juvenile anadromous fish outmigration. The deduction during 1980 was representative of the FERC agreed upon water quantities for spill at mid-Columbia projects and an amount based on January-July runoff at The Dalles for Lower Columbia Federal projects (figures available on request - PRC). While spill reductions from available power resources do not directly affect load forecasting, this reduction does show the incorporation of fisheries concerns in the power planning effort.

Under the proposed Pacific Northwest Electric Power Planning and Conservation Act, it is likely that fishery and other nonpower uses of the Columbia River will be further integrated into the power planning process. Specifically, Section 4(h) of both the Senate Bill (S. 885) and the House's version (H.R. 6677), require the submission of a fisheries plan by the Region's fishery agencies and Indian tribes which is to be incorporated into the power plan by the Pacific Northwest Electric Power and Conservation Planning Council. Such recommendations by the fishery agencies and interests are to include measures to protect, mitigate, and enhance fish and wildlife; and the development of fish and wildlife research that among other things will improve passage conditions at and between the Region's hydroelectric dams.

Letter No. 50, Comment No. 14

We agree with the first sentence of the comment and certainly view fishery agency input as an essential and an important nonpower consideration in the development of any power planning document. However, it would be inappropriate to propose detailed and prescriptive requirements for public (including fishery) involvement in this EIS. BPA presently has an established public involvement program governed by a published procedure which provides extensive opportunities for public participation at critical junctures in the development of major power marketing policies.

Letter No. 50, Comment No. 15

Refer to Letter No. 21, Comment No. 1 and Comment No. 4 of this letter.

Letter No. 50, Comment No. 16

A list of potential programs was presented in the Revised Draft EIS on page III-24.

Letter No. 50, Comment No. 17

Under Alternative 3, pages III-53 to 62 of the RDEIS, the EIS discusses BPA's involvement in the areas of customer services, transmission planning, power planning, conservation, sources of power, etc. A similar structure is used for the other alternatives and the proposal. Accordingly, by comparing the provisions of the proposal to those under Alternative 3, one can readily see the application of these areas under the proposal. In making this type of comparison, the proposal represents what BPA feels is the optimum use of its existing authority. This type of comparison is also facilitated through the provision of Table III-1.

Letter No. 50, Comment No. 18

The operation of the FCRPS occurs within limits established by the operating agencies and licensing authorities. These limits are established to protect the other users of the Columbia River water resource, including fish and wildlife. Any action BPA takes or proposes to take must fall within those operating constraints. Since the FCRPS currently operates within these approved levels and our proposal will not require modification of the constraints, there will not be any additional impact to fish and wildlife resources from BPA's proposal in the Revised DEIS.

Where a BPA proposal would require relief from an existing constraint, the action would be subject to NEPA compliance. An example of this is a BPA-funded study to evaluate the effects of "zero" river flow during water storage operations at Snake River hydroelectric facilities. This study seeks to identify the need for differing minimum flows during the summer and winter to protect migratory adult salmon and steelhead. Should the study show the fishery resource is not impacted, an existing operational constraint might be reduced. The study itself is a part of our NEPA compliance process.

Letter No. 50, Comment No. 19

The referenced discussions are presented as part of a description of the, "Hydro Peaking Transition," beginning on page IV-10 of the RDEIS.

In presenting this material, the document attempts to identify the patterns and trends currently affecting this transition which are in turn an influence on the operation of the river system. Accordingly, these discussions describe aspects affecting the operation of the existing system and are not presented as BPA proposals. However, paragraph (c) does clearly indicate that "tailwater fluctuations will increase."

Letter No. 50, Comment No. 20

The Pacific Northwest Coordination Agreement would continue to have its effect on Pacific Northwest power operations regardless of which of the several alternatives outlines in the RDEIS might be implemented. Modifications may be necessary, again depending on which alternative may come into play. Interutility coordination and cooperation are discussed under each of the alternatives described in the text. References can be found under the headings:

III.B(or D, E, F, and G).1.d. Power Planning
III.B(or D, E, F, and G).2.d. Cooperative Arrangements
(1) Resource Operations
(2) Resource Planning and Construction

Letter No. 50, Comment No. 21

The text has been revised to accommodate the comment. Refer, also, to Letter No. 21, Comment No. 4 and the changes made in the text.

Letter No. 50, Comment No. 22

This is not true, nor was it intended to imply that the anadromous fishery is for commercial use only. We only point out here, that the major emphasis of fisheries research, the greatest economic value, and the largest public concern rests with the anadromous fisheries and not with the residential fishery of the Columbia River and its tributaries.

Letter No. 50, Comment No. 23

Refer to the next comment.

Letter No. 50, Comment No. 24

We believe our assessment of the cause of declining populations of salmon and steelhead in the Columbia Basin is both accurate and adequate. While acknowledging that the construction and operation of hydroelectric facilities have been a major, and perhaps the major, cause of this decline, other developments have also significantly contributed to this decline. Among these are habitat destruction associated with poor logging, mining, and agricultural practices; water quality changes from agricultural, municipal, and industrial pollution; and the heavy demands placed on the fishery resource by in-river and ocean commercial, sport, and Indian fisheries. Natural environmental changes and phenomena may also significantly affect the fishery resource. It is suspected that the lack of coastal upwellings has caused the decline of coho salmon populations off the Pacific Coast in recent years; and the eruption of Mt. St. Helens in May 1980 resulted in total destruction of fish life in the Toutle River in Southwest Washington and unknown impacts on the general population of fish in the Columbia River.

It should not be construed, however, that BPA does not share in the responsibility for any actions which may have impacted the salmon and steelhead resource in the Columbia River. Our responses to Letter No. 21, Comment No. 4 and Letter No. 35, Comment No. 6 and 7 reflect our concern for the fishery resource .

Letter No. 50, Comment No. 25

We believe the revisions to Chapter IV.A.1.a accurately reflect the cooperative effort to protect and enhance the salmon and steelhead resource of the Columbia River and its tributaries.

Letter No. 50, Comment No. 26

Refer to the BPA Draft Role EIS, Appendix A, Chapter III, for an expansion of impacts resulting from the operation of the FCRPS.

Further, while revisions to pages IV-15 through IV-17 of the Revised DEIS do not expand on our initial presentations, the references to this discussion include the impacts and losses identified in this comment.

Letter No. 50, Comment No. 27

The text has been revised to accommodate the comment.

Letter No. 50, Comment No. 28

Refer to the BPA Draft Role EIS (July 1977), Appendix A, Chapter III, for an explicit discussion of hydroelectric generation and fishery impacts. Comment No. 26 of this letter also addresses a similar issue.

Letter No. 50, Comment No. 29

Addressing the second point of the comment first, BPA maintains that substantial commitments have been made to preservation of Columbia River salmon and steelhead in the recent past. Through cooperative efforts between fishery and operating agencies in forums such as the Committee on Fishery Operations, agreements to improve migration of juveniles and adults have been developed and implemented.

For example, in a memo dated July 22, 1980, from Robert Lamb, BPA Hydrometeorology Section Head (and Cochairman for COFO during 1980) to Larry Dean, Chief, Branch of Power Supply, the cost of spill used during the "Fish Flush" operations since 1977 were summarized as follows:

	1977	1978	1979	1980
Federal System	90,100 MWh	109,703 MWh	142,054 MWh	196,046 MWh
Non-Federal System	76,800	160,306	203,154	161,630
Total MWh	166,900	270,009	345,208	357,676
Barrels of Oil	278,000	450,000	575,000	600,000

With the current cost of oil estimated at $32 per barrel, spill provided in 1980 could have been used to displace $19 million worth of oil. While the intent of this discussion is not to say $19 million of oil was "wasted" during the 1980 operation for fish, it is important to realize that this effort represents a significant commitment by the operating agencies to protect the fishery resource.

The first point of this comment relative to mitigation and compensation was discussed in other responses to comments on the Revised Draft EIS. Under the provisions of the proposed Pacific Northwest Electric Power Planning and Conservation Act, BPA's authority and responsibility to protect, mitigate, and enhance fish and wildlife resources would greatly expand. However, at present our authority and role dictate otherwise.

Letter No. 50, Comment No. 30

Revisions to the text have been made to accommodate the comment.

Letter No. 50, Comment No. 31

Revisions to the text have been made to accommodate the comment.

Letter No. 50, Comment No. 32

Alternate ways of "running the river" are beyond the scope of this programmatic EIS. Once other substantially different coordinated river operation schemes are proposed, joint exploration of the schemes by all agencies and entities having operational or management responsibilities on the Columbia River and its tributaries would have to be undertaken. Such an undertaking would likely take years to accomplish and would almost certainly require its own EIS.

Letter No. 50, Comment No. 33

As mentioned previously, and on page I-19 of the RDEIS, this document is not an implementation EIS. Rather, the EIS attempts to examine only the affect/relationship of varying levels of cooperation/coordination on regional power planning and not what specific measures would be needed to effectuate a given level of regional cooperation/coordination. Yes, as indicated in Alternatives 3 and 4, changes in the regional decisionmaking process would be necessary for improved accommodation of environmental and other concerns.

Letter No. 50, Comment No. 34

Revisions to the text have been made to accommodate the comment.

Letter No. 50, Comment No. 35

This is not the only place in the RDEIS where the issue of cooperation/coordination is addressed. It is also discussed on several occasions for each alternative under the following headings: "Power Planning," "Public Involvement," "Alternative Regional Structure," "State and Local Government," and "Cooperative Arrangements." Given the number of references, the issue is not felt to have been dealt with superficially.

For reasons stated in the response to this letter, Comment No. 33, specific "modes" and their impacts are not analyzed. However, the consequences of less regional cooperation and coordination, for example, are analyzed under Alternatives 1 and 2.

Letter No. 50, Comment No. 36

See response to Comment No. 33 of this letter.

Letter No. 50, Comment No. 37

Bonneville's position with regard to the applicability of the FWCA is reflected in our response to Comment No. 4 of this letter.

Beyond that the impacts to non-power considerations presented in the context of a major resource insufficiency are not felt to be inconsistent. As mentioned in the text the major steps of mitigating or offsetting the likelihood of the resource insufficiency described include use of the interruptible portion of the DSI load available to the system and the lead times provided by the power planning process. These lead times allow for the development of conservation measures, the development of alternative resources, and the purchase of power from outside the region.

Letter No. 50, Comment No. 38

We feel the referenced discussion of nonpower issues is both accurate and adequate for this programmatic EIS.

Letter No. 50, Comment No. 39

The discussion of impacts in IV.B.2 is only intended to present a generic appreciation of the impacts of 21 different resource types, including load management. Consequently, this discussion is not intended to support a decision to implement load management.

Letter No. 50, Comment No. 40

The section entitled, Potential, on page IV-119 of the RDEIS has been revised (in response to Letter No. 48, Comment No. 13) to reflect current forecasts.

Letter No. 50, Comment No. 41

It is beyond the scope of this document to address the cumulative impacts of existing dams on the fisheries resource in the Columbia River. Information on these impacts is readily available and was identified in BPA's Draft Role EIS (July 1977). In the proposal stage of new hydroelectric facilities, through either the licensing process or Federal involvement, environmental documentation will be required as a part of NEPA compliance. Examples of this are the Corps' ongoing work at the proposed Ben Franklin project site and Grant County Public Utility District's proposal to expand their Priest Rapids and Wanapum projects.

Our revision of Chapter IV.A.1.a. now includes references of a more recent nature. While specifics are not presented in the Revised Draft

EIS, these current references when taken with the Draft Role EIS (BPA, 1977) accurately portray the situation relative to the Columbia River salmon and steelhead resource.

Letter No. 50, Comment No. 42

Refer to our response to Comment No. 41 of this letter. Discussions of the nature suggested here are beyond the scope of this document. Environmental documentation will occur at the time of development along with coordination with either the State fish and wildlife authorities and/or Federal fish and wildlife agencies. Any Federal involvement in small hydro development will bring NEPA and other Federal environmental laws into play.

BPA states that "bulb turbines may result in less impact . . . ," not that it will result in less impact. Further, in 1980 the amount of spill required at Rock Island Dam on the Mid-Columbia was reduced because of improved passage conditions through the bulb turbines. This reduction resulted from the review of tests run at Rock Island during the 1979 migration season designed to measure the mortality associated with passage through bulb turbines *versus* conventional turbines. Although the results were somewhat inconclusive, a technical committee which reviewed these results felt sufficient information existed to reduce the required amount of spill from the FERC agreement.

Letter No. 50, Comment No. 43

BPA is constrained in its operation of the FCRPS within certain operational limits. It is inherent in the scenarios that the hydrosystem will operate within these limits and that impacts will not increase over existing levels. Should a proposal be made to change these operational limits, appropriate environmental review will be necessary as a part of NEPA compliance.

Letter No. 50, Comment No. 44

The subject of evaluation in this EIS is the one-utility concept. The alternatives presented are alternative levels of adherence to the one-utility concept. The "worst case" scenarios were developed because the outcome or resource mixes associated with the alternatives are not known. As pointed out in the text, the scenarios are worst case only in terms of their reliance upon a particular generation or resource type. The scenarios were not designed, for example, to represent worst case analyses for any specific wildlife resource, fisheries included.

Letter No. 50, Comment No. 45

See previous response.

Letter No. 50, Comment No. 46

GAO opinions regarding reserves have little support from the regions utilities who are obligated to maintain the system reliability. GAO does not provide substantiation for their findings, and their report is not updated to recognize changing conditions. Large delays in the thermal plant installation schedules result in greater peak deficiencies in spite of reduced peakloads (see Power Outlook, 1980).

Letter No. 50, Comment No. 47

The 448 MW referred to in the EIS is a product of specific assumptions within the PNUCC econometric electric energy sales forecast. During the course of a public workshop of utility and non-utility representatives, the thoughts of the representatives are collected concerning future solar space and water heating, residential insulation levels, and a variety of other topics. The beliefs of these representatives are then directly used in the preparation of the PNUCC econometric electric energy forecast.

With the above procedure in mind, we see that the 448 MW referred to in the Revised Draft EIS and in the comment, is in fact, an integral part of the forecast and not some add-on by BPA. The PNUCC methodology is fully described in the documents entitled, "Econometric Model--Electricity Sales Forecast."

Changes to the text have been made to clarify this topic of discussion.

Letter No. 50, Comment No. 48

Combustion turbines are being installed by various utilities in the region to provide peaking at the load center. Also, future large thermal plants can be expected to have more load following capability than they are credited with in this EIS. Studies in detail of these possibilities and the use of synthetic fuels are underway at this time but are not available for inclusion.

Letter No. 50, Comment No. 49

The scenarios presented were not intended to be realistic projections, but, instead, were meant to be extreme cases for the purpose of analyzing worst-case environmental impacts. It is true that the effect of increasing cost is to depress demand (although not necessarily through conservation), but in assessing streams of environmental impact. It was not considered necessary to adjust demand, mainly because of the uncertainty of future resource cost.

Letter No. 50, Comment No. 50

Refer to Chapter IV.A.1.a. of the Revised Draft EIS. In this section the impacts of hydro development are summarized. The increased impact due to the development identified in Scenario A is summarized in Chapter IV.B.3.c.(1).

Letter No. 50, Comment No. 51

The conservation achievement applied to Scenario B was the maximum potential drawn from the discussion on pages IV-102 through IV-109 of the RDEIS. The 10,517 MW peaking value was based on the assumption that conservtion would affect daytime peakloads more than nighttime loads. Note 1 on Table IV-34 of the DEIS, explains the method which was used to estimate this effect, a procedure which was necessary due to the lack of infor- mation on the effect of conservation on peakloads.

Impacts of hydro development are discussed in general on pages IV-15 to IV-25, IV-119 to IV-123, and IV-156 to IV-158 of the RDEIS. Specific impacts of hydro capacity additions for Scenario B are discussed on page IV-204 and shown in Table IV-35 on page IV-201.

Letter No. 50, Comment No. 52

The impacts of hydro development were presented in the RDEIS on pages IV-15 to IV-25, IV-119 to IV-123 and IV-156 to IV-158. The specific impacts of hydro capacity additions for Scenarios C, D, and E were discussed on page IV-205 and Table IV-37, page IV-209 and Table IV-39, and page IV-214 (Table IV-41), respectively.

Letter No. 50, Comment No. 53

Refer to the previous comment.

Letter No. 50, Comment No. 54

The use of the existing system as a baseline for comparison provides the EIS and the reviewer with a familiar and quantifible basis for evaluation. This choice was not intended as an endorsement of the impacts associated with the operation of the existing system, nor is it seen as institutionalizing these impacts.

Letter No. 50, Comment No. 55

The reference cited simply states that if loads are less, ". . . then the generation resources necessary to meet load will be less and the environmental impact from generation resources will be less." This statement in no way implies, nor does it follow, that new generation would be developed irregardless of load forecast.

Letter No. 50, Comment No. 56

Both of these references point to BPA's limited ability to influence energy development patterns under existing authority. For example, on page IV-235 of the RDEIS, BPA's influence is limited to "persuading and inducing."

The only concrete option available to BPA for affecting resource development is the provision of services. However, as discussed in the discussion entitled, "Effect of BPA Integrating Services," page VI-255, "BPA's service policy does not enable the development of a specific resource type as much as it enhances the development of all resource types . . ."

Letter No. 50, Comment No. 57

BPA is not proposing any specific programs in this document. Comparative impacts of specific potential load management programs and their alternatives will be evaluated when such programs are proposed.

Letter No. 50, Comment No. 58

As indicated in the referenced discussion, the main provision of the proposal is the continued provision of services. The discussion on page IV-263 of the RDEIS is more an indication of what would not be done under the proposal, an equally important clarifi- cation. These clarifications help to distinguish the proposal from the alternatives.

BPA has already implemented cost-based peakload management through the application of higher seasonal and daily capacity rates. In addition, Bonneville is currently investigating the effectiveness of other load management techniques being used at the retail level. To substantiate these evaluations, Bonneville is considering for example a pilot program to test radio controlled water heaters.

Since the Revised Draft EIS does not present discrete program proposals, the proposal and alternatives are not distinguished at the program level. Instead, the EIS examines alternative roles for BPA and alternative institutional arrangements governing the regional power planning process. A range of programs are possible under these alternative institutional arrangements.

Letter No. 50, Comment No. 59

Please refer to our responses for Comments No. 27 through 30, and Comments No. 33 and 34 of this letter.

Letter No. 50, Comment No. 60

This is one of the more significant reasons that lead to our conclusion regarding the environmentally preferable alternative (RDEIS, page IV-334).

LETTER NO. 51

Natural Resources Defense Council, Inc.

Letter No. 51, Comment No. 1

NRDC has suggested that the goals of the Role EIS should include "the transmission facilities, powerplants, hydropower adjustments, and other actions involved in a major shift to thermal supply resources under a "one-utility approach." It is NRDC's assertion that this constitutes the "major Federal action" issue.

BPA's response is that there is no attempt to establish a program, in fact, no program which constitutes a major shift to thermal supply resources is now in existence. The "one-utility" effort in the region anticipates the coordination of such resources as may be developed, but the system itself is not actually engaged in promoting new thermal resources to the exclusion of other unconventional resource development, as was the case under phase 1 and phase 2 of the Hydro Thermal Power Program (HTPP).

BPA has examined into "reasonable alternatives" to thermal resources in its examination of conservation and renewable resource development. This examination was done on a generic basis and is part of the information available to the decisionmaker in the EIS.

Referring back to Judge Skopil's decision, it needs to be emphasized that the most significant element of each HTPP2, as identified by the court, is the "one-utility concept." BPA's position is not so much that energy resource development is "exogenous" to this concept, but that it is dependent upon the application of the concept. Recognizing this and considering also that the region is currently in the process of selecting from among alternative approaches to the one-utility concept serves to reinforce the validity and timeliness of evaluating this issue in the Role EIS. Given the interest in the development of the Northwest Regional Power Bill, this issue cannot be regarded simply as "abstract questions of interutility coordination."

Letter No. 51, Comment No. 2

As indicated in the above response, BPA views the institutional issues (alternative planning processes) as the primary concern with resource issues being dependent or of secondary concern. It is only because the region is currently trying to resolve the institutional issues that the resource questions are characterized as unresolved. The alternative resource scenarios discussed in the RDEIS are presented in that context, and for that reason are hypothetical. However, these scenarios are not overlooked in the discussion of the proposal and alternatives. On the contrary, the relationship of the scenarios to the proposal and alternatives is presented in the Revised Draft EIS in Chapter IV.E and in Table IV-51.

The reference cited from Chapter 1, is not a statement of a BPA proposal, but is a characterization, in very general terms, of the ultimate energy planning question to which the region must respond. However, before that response can be formulated, a process providing for its formulation must be developed and implemented.

We would agree, therefore, that "coordinated planning is not an end in itself," however, we disagree with NRDC's conclusion that "coordinated planning" cannot avoid significant environmental impacts. We feel there are issues of substance associated with the planning process since it is the process that determines "how the regions future electricity needs will be met."

Letter No. 51, Comment No. 3

The comment suggests that BPA should have a definitive position regarding the region's future thermal power needs prior to the time it has performed the base studies required to prepare a comprehensive regional load forecast and power planning document. But it is the studies and planning that constitute BPA's proposal at this time--not the conclusions to be drawn from studies not yet completed. Any resource specific program which would come from regional planning efforts would be the subject of subsequent environmental consideration.

As stated on pages III-14 and 15 of the Revised Draft EIS, the planning document which BPA is proposing would have to include: 1) a regional load forecast (discussed on pages III-13 and 14); and 2) a consideration of resource and conservation programs for the region, among other things. Regarding the regional load forecast, even now BPA is proceeding to gather the end-user data from the residential, commercial, and industrial sectors. This data is necessary to improve load estimating and is a prerequisite to realistic assessment of power program potential in the region. Simultaneously, the PNUCC is taking steps to improve and expand its econometric model which provides a check to utility load forecasts.

Bonneville is also preparing preliminary resource and conservation assessments in order to define the generic potential and impediments to implementing power strategies in the region. BPA's conservation assessment will be published in late 1980. Other regional utilities and government agencies are also proceeding to improve forecasting techniques, and are investigating and implementing conservation and resource development programs.

The comment also suggests that BPA should have such a planning document completed now or in the near future. The development of an annual planning document is a project requiring the sequential completion of a number of independent steps. It is not something that springs forth full grown from existing regional utility planning functions. BPA's forecasting and assessment efforts are the first steps in developing such a document, and these are underway. Another important step will be taken by Congress this year--the decision whether to provide the region with new legislation affecting BPA's role in regional power supply or to allow BPA's administrative allocation of Federal power to proceed. Either course will dramatically affect the planning process the region must undertake. The preliminary steps which BPA and other regional interests have begun will be consistent with and useful in either case.

Letter No. 51, Comment No. 4

A summary of the elements of the proposed allocation policy has been included in Chapter III of the FEIS for purposes of information only. Bonneville's reasoning for not including an analysis of the allocation proposal and alternatives are still valid and are presented below.

First, allocation is not an element of the proposed program. The proposed program is one of regional cooperation and coordination (the one-utility concept). "Agencies shall use the criteria for scope...to determine which proposal(s) shall be the subject of a particular statement." 40 CFR 1502.4(a). "Scope" consists of the "actions, alternatives, and impacts to be considered in an EIS." 1508.25. Allocation is not an:

- "Action," 1508.25(a), because it is not "closely related" to the one-utility concept. The two concepts are fundamentally different. The one-utility concept refers to a cooperative approach to the solution of the energy supply problem. The allocations concept refers to the division of the Federal energy supply between eligible customers, not to the regional supply of energy.

- "Alternative," 1508.25(b), because allocation is not a course of action which can be undertaken in lieu of the proposed program, nor does it constitute "no action."

- "Impact," 1508.25(c), because the allocation of Federal energy is an independent action, not an impact, effect, or result caused by the one-utility program.

Thus BPA's allocation proposal is not properly within the scope of the Role EIS, according to the CEQ's NEPA regulations. The revised Draft Role EIS describes and develops alternative levels of cooperation in the Region.

Second, there is no decision which must necessarily be made on the allocations issues at the time the decision is made on the regional cooperation issues. These decisions can be made independently; one does not influence the other. "NEPA procedures must insure that environmental information is available to public officials and citizens before decisions are made and before actions are taken." 1500.1(b). But environmental information on the allocations proposal is not essential to decisions on the proposed program described in the Revised Draft Role EIS. The reverse is true as well. There is no danger that the decisionmaker will "ignore relevant issues," as the comment suggests.

Thus it is not required that the allocation proposal need not be analyzed in this EIS.

Third, the CEQ recognizes that there may be "related" issues which are beyond the scope of the EIS currently under preparation. In these cases, agencies are to indicate "impact statements which are being or will be prepared that are related to but are not part of the scope of the impact statement under consideration." 1501.7(a)(5). BPA agrees that the allocation issues are "related" to the cooperation issues, as both are "issues concerning the Regional power program." But as pointed out above, the allocations issues fall outside the scope of the Role EIS. BPA has indicated that an allocation EIS is currently under preparation. This is hardly a "welter of fragmented analyses," as the comment suggests. Rather, it is a methodical approach to best "insure that the policies and goals defined in [NEPA] are infused into the ongoing programs and actions of the Federal Government." 1502.1. This approach is both legal and logical.

<u>Letter No. 51, Comment No. 5</u>

The conservation proposal included in the Revised Draft EIS is a <u>policy</u> proposal, not a <u>program</u> proposal. The individual programs to be implemented under BPA's conservation policies cannot be specified at the programmatic level. Selections of incentives, estimates of expenditures, and demand reductions depend upon information which is just now being gathered. Specific programs will be selected as the regional power situation requires and as BPA's authority permits.

The details of BPA's conservation <u>program</u> are not intended as part of a general <u>policy</u> statement such as that presented in the Revised Draft Role EIS. Policy implementation will be carried out under the stated policy principles with regard given to BPA's other statutory functions, relationships with utilities, and the immediate requirements of the power situation in the region. Additionally, NRDC has apparently confused its concept of what it wants to do with what BPA can do as a matter of fact and law. BPA's present authority to undertake conservation programs is very limited. The authority is as follows:

> "Authority to engage in conservation activities must be derived by implication of BPA's power marketing and transmitting responsibilities. The participation of BPA in an extensive conservation program which is not directly related to and subservient to its power marketing and transmitting responsibilities would require expressed congressional approval . . . ."

Without such expressed authority, BPA may do no more than is described in the RDEIS.

<u>Letter No. 51, Comment No. 6</u>

The reference cited on page I-23 of the Revised Draft EIS is taken from the Overview chapter which attempts to summarize the reviewers comments on the original Draft EIS, and, as such, is not a statement by BPA describing its affirmative obligations. Nevertheless, even though there is no proposal for resource selection/development in the RDEIS, the document does present a conservation scenario (Scenario B). This scenario is presented with four other "worst case" scenarios to compare and contrast the impacts of conservation to renewable and conventional resource development. These scenarios are referred to as "worst case" because of their extreme or extensive reliance upon a given resource type. The reason for utilizing this "worst case" approach is because an analytical basis for formulating a "maximum credible, regional and BPA energy conservation scenario" does not exist. In fact, this basis is just now being compiled and developed. Nevertheless, the NRDC Alternative Scenario, which is portrayed as a maximum credible conservation scenario, has been represented in the Final EIS's discussion of alternative resource scenarios. It needs to be pointed out that the Alternative Scenario is based upon a series of assumptions rather than detailed end-use data.

Letter No. 51, Comment No. 7

The list of measures and programs on pages III-24 and III-25 of the Revised Draft EIS reflect suggestions made to Bonneville or ideas generated within the agency. When a viable conservation measure is suggested or engendered, Bonneville evaluates the idea from the point of view of technical potential, authority, cost-effectiveness, engineering feasibility, and overall feasibility. The measures listed are presently undergoing this kind of analysis.

Also see Comments No. 4 and 5 of this letter.

Letter No. 51, Comment No. 8

Bonneville is presently studying rates which encourage conservation and other rate designs most applicable to the Bonneville system. Bonneville is committed to encouraging conservation, although the conservation rate alternatives available to Bonneville are somewhat dependent upon existing authority and pending legislation.

The discussion of time differentiation of rates in the EIS for the 1979 Wholesale Rate Increase, October 1979, pages VI-9 to VI-29, is an example of current rate design which promotes conservation through load management.

Further discussion of conservation rates can be found in the 1979 Wholesale Rate Increase EIS on pages VI-39 to VI-47.

Refer to Letter No. 36, Comment No. 2 for a discussion of Bonneville's authority to implement rates based on cost differences between thermal and hydroelectric generation plants.

Letter No. 51, Comment No. 9

As indicated previously, BPA is not proposing nine or any other number of thermal plants designed to meet the region's resource needs. In contrast to its role in the Hydro-Thermal Power Program, BPA at present has no role, active or otherwise, in the financing of new thermal plants. The reference cited (IV-25) is a discussion of the existing system. This discussion (Chapter IV.A) is intended to serve as the baseline for subsequent evaluations and is not a BPA proposal. However, in a generic sense, the impacts from choices of resource mix may be found in Chapter IV.B. Additionally, alternatives to the continued development of central station generation have been presented as Scenarios A and B, and in Chapter IV.B.3.

The direct service industrial customers (DSIs) have been notified that their needs will not be met by BPA in the future. However, the impact of serving the DSIs is addressed in Chapter IV.A. The only "proposal" left is the continued provision of services (page III-8 of the RDEIS). The impacts of BPA's proposed continued provision of services, including its effect upon resource development, are fully evaluated in Chapter IV.A, IV.C, and IV.D.

Although Scenarios A and B were presented as alternatives to central station generation in the Revised Draft EIS, the Final EIS has been expanded to include the NRDC Alternative Scenario. However, even the Alternative Scenario assumes that some conventional plants will be built.

Letter No. 51, Comment No. 10

BPA does not dispute conclusions regarding the relative cost advantages of conservation. This does not mean that the costs of conservation are either well known or unchanging. The convincing cost advantages cited are conjectural, but could have been used in this EIS. However, the purpose of this EIS was not to evaluate specific conservation activities, but was to indicate the range of potential environmental impacts of the programmatic alternatives presented. For this purpose a detailed analysis of cost was not feasible.

Additionally, none of the references cited provide an analysis by the end-use sector with the same level of detail as the SOM report. All were equally dependent upon assumptions about end-uses, due to the absence of survey data which is only currently becoming available. However, the NRDC Alternative Scenario was included for purposes of comparison in the Final Role EIS.

The cost estimates provided in Table IV-5 (page IV-49, RDEIS) have been updated.

Letter No. 51, Comment No. 11

As indicated above, a summary of the NRDC Alternative Scenario has been included in Chapter IV.B.3. In addition, a detailed, technical evaluation of the Alternative Scenario has been prepared by BPA and is included in the Final EIS.

Letter No. 51, Comment No. 12

Again, the obvious disagreement is over the scope and subject of the Role EIS. However, it should be pointed out that both NRDC and the President's Council on Environmental Quality (CEQ) participated in the development of the outline for the Role EIS. The purpose of the Role EIS at the onset, as is now, was to study the dynamics of BPA in the Pacific Northwest power planning process. This is precisely the focus presented in the Revised Draft EIS.

As reflected in the interest over the Regional Power Bill, both regionally and nationally, the issues addressed in the Revised Draft EIS are hardly "neutral management issues." This is not intended to belittle the importance of resource issues. The disagreement stems from the fact that Bonneville views resource issues as secondary, i.e., as being dependent upon resolution of the institutional/process problems and concerns.

Therefore, while it is true that over the past few years there has occured a widespread recognition of the advantages of unconventional/-renewable resource development as compared to conventional resource development, it is also true that the Role EIS does not propose any of these. It leaves the energy sufficiency proposal for another study, another EIS. This intent is clearly described in the Revised Draft EIS on pages I-19 and 20.

LETTER NO. 52

Ms. Barbara D. Rhodes

No response required.

LETTER NO. 53

U.S. Environmental Protection Agency; Region X

Letter No. 53, Comment No. 1

The electric energy and demand forecast used in the discussion of alternative resource scenarios includes three major forecast-related topics. The three identified topics include: 1) the nature or method of preparing the energy and demand forecast; 2) the role of energy prices and supply considerations in the forecasts for electricity; and

3) the impact on electricity prices of new, expensive thermal generating plants.

The first element of this comment concerns the apparent assumption by BPA that the historical growth in energy and peak demand of electricity experienced between 1972 and the present will continue into the 1980's and 1990's. This presumption brought forth in the comment is incorrect. The methodology of the forecast of energy and peak is clearly stated as including the energy forecast of the PNUCC econometric electric energy forecasting model, which utilizes explicit forecasts of population, employment, income, and other factors rather than relying upon historical trends, and the use of the PNUCC Long-Range Projection of Power Loads and Resources, that forecasts peak electricity demand by the 123 electric utilities within the PNUCC by a variety of techniques. Few, if any utilities rely exclusively on a trend of historical requirements.

In any case, the observed historical growth in peak demand and energy between 1972 and 1978 was 4.32 percent and 3.82 percent, respectively. These historical values are considerable different than the 3.5 percent referred to in the comment.

The second element of the comment expressed the belief that the growth in electric energy demand between 1972 and 1978 was positively affected by two unique and nonrecurring events: the 1972 oil embargo, and the restriction of natural gas deliveries to the United States by the Canadian Government. These beliefs may be correct. However, the PNUCC econometric energy forecast relies upon explicit forecasts of the prices of natural gas and oil as determined in a public workshop of utility and non-utility representatives. The workshop participants were free to select any growth rate in these energy prices they felt appropriate after hearing a series of oil experts express their thoughts on future energy price and supply considerations. Although we are unable to identify the implicit assumptions concerning U.S. energy policy, OPEC, or Canadian Government actions the workshop participants made, the oil and natural gas real price assumptions employed in the econometric forecast for 1978 to 1998 are listed below:

Real Price Forecast
1977 to 1997

(Average Annual Rate of Growth)

Natural Gas

Residential	-	2.78 percent
Commercial	-	3.21 percent
Industrial	-	4.33 percent

Petroleum

Commercial	-	2.81 percent
Industrial Fuel Price Index	-	4.28 percent

The third element of this comment was concerned with the impact of new thermal plants, such as the Washington Public Power Supply System, on the average price of electricity in the region. The PNUCC econometric energy forecasting model includes an electricity pricing submodel within its framework. The purpose of the electricity pricing submodel is to prepare an electricity sales forecast which is consistent with the costs of generating the electricity. The pricing submodel calculates the average price of electricity sold to each major consuming sector by calculating the generation and nongeneration costs associated with new existing energy loads. The real electricity price forecasts calculated by the PNUCC pricing submodel are listed below.

Real Electricity Price Forecast
1977 to 1997

(Average Annual Rate of Growth)

Residential	-	2.15 percent
Commercial	-	2.31 percent
Industrial	-	3.58 percent

The above electricity price forecasts reflect the higher costs associated with new thermal generation. For example, the PNUCC estimates the costs of serving existing residential customers at 16.84 mills/kWh in 1977 constant dollars. Future load growth in the residential sector, however, is estimated to cost 31.853/kWh in 1977 constant dollars. (Consumers, pending revolutionary changes in rate policy, will be faced with the average rather than marginal cost of electricity.)

Although the average electricity price and other fuel prices are forecast to increase substantially in real terms over the forecast period, they are not expected to reverse the relative cost advantage electricity enjoys in this region.

In summary, the electric energy and peak forecast employed in the Revised Draft EIS is not a simple extension of historical experience. Rather, the PNUCC econometric forecast is a product of a complex, computerized model which explicitly includes the impact of changing natural gas, oil, and electricity prices. Although the real prices of all energy forms are anticipated to rise significantly, the average price of electricity will continue to experience its relative price advantage when compared to natural gas or oil.

Letter No. 53, Comment No. 2

This complex question and comment has many facets; however, it appears the overriding concern of the EPA is that the Final EIS needs to examine, in some detail, the current debate between power and nonpower interests in the pending Pacific Northwest Electric Power Planning and Conservation Act. We should point out that Alternative 3 of the RDEIS summarizes BPA's role and the impacts from new legislation such as the legislation currently befoie Congress. Realizing that even proposed legislation would not change BPA's authorities until it was enacted and implemented, and for the reasons stated in the RDEIS on pages I-26 and I-27, we have chosen not to expand the Final EIS as suggested.

Relative to the power/nonpower debate over Regional energy legislation, the majority of the environmental concerns identified to date deal with protection of the anadromous fishery resource. Under the existing authorities, the river operating agencies maintain that they lack authority to provide required passage conditions (as identified by the Region's fishery management agencies). Although the proposed energy legislation is single purpose in nature, BPA supports the inclusion of fishery protective measures which can lead to a more harmonious operation of the FCRPS with fishery and other environmental resources of the Columbia River.

As currently drafted, S. 885 and H.R. 6677 require the consideration and inclusion of a fishery plan as recommended by the Region's fishery agencies, Indian tribes, and other interested groups. All power planning efforts would then be developed in coordination with the fishery plan. Additionally, the proposed legislation and its fishery language would bring the fishery community (as individual entities or via a commission) to the planning table as an equal in reference to authorized use of the water resource. The early inclusion and discussion would allow equal consideraion of power and fish, and the development of necessary power operations with the benefit of the fishery resource in mind.

To further address the specifics of this comment, BPA feels that the original Draft Role EIS (BPA, 1977) adequately presented the issues relative to power/nonpower conflicts. As a result of comments to the Revised DEIS, the section on fishery resources (page IV-15 to IV-17 of the RDEIS) has been expanded to update and summarize the issues identified in 1976. We have also included a bibliography with this discussion which further expands the coverage of fishery and water-related resource issues.

With regard to the FERC-ordered fishery studies at mid-Columbia Public Utility District hydroelectric dams, we feel an in-depth discussion is beyond the scope of this document. Furthermore, the results of these studies, of up to 5 years in duration, are not available at this time. It should be noted that spill levels similar to the FERC required amounts were included in the PNUCC West Group Forecast and Annual Operating Plan (refer to response to Letter No. 50, Comment No. 13). During the past 3 years, the Federal System has been voluntarily operated in a manner that has allowed the PUDs to meet Columbia River Fisheries Council recommended flows and the FERC spill levels during the majority of the juvenile salmon and steelhead migration season.

Our revised discussion of fishery impacts, found in Chapter IV.A.1.a, contains an expanded explanation of institutional arrangements for Columbia River water management. In the past few years, the existing organizations and committees have been more successful in arranging operations that benefit the fishery resource while providing operating flexibility to the hydroelectric generating system. As pointed out earlier, these arrangements should be further solidified if pending Regional energy legislation is passed into law. Currently, these committees are plagued by lack of authority with membership and recommendations achieved through the voluntary action of those involved. With fishery resources being identified as an equal user of the water resource of the Columbia River in pending legislation, the current ad hoc structure of many of these committees would be replaced by the responsibility to work with the power planning structure.

As to the suggestion that legislation should be enacted to develop a new inter-State Columbia River System management agency, BPA would generally not support such action. It is unlikely a newly formed body could be any more effective than an existing organization. It appears the current limiting factors to the effectiveness of all interagency management groups have been the individual agencies' ideological goals and legal responsibilities, and the degree of legal stature afforded fish and wildlfe resources of the Columbia River Basin. Although ideological goals and legal responsibilities will not change, it appears Regional energy legislation will elevate the status of the fish and solve the latter problem.

LETTER NO. 54

State of Washington; Department of Ecology

Letter No. 54, Comment No. 1

Revisions to the text have been made to accommodate the comment.

Letter No. 54, Comment No. 2

Revisions to the text have been made to accommodate the comment.

Letter No. 54, Comment No. 3

The text has been revised to accommodate the comment.

Letter No. 54, Comment No. 4

Based on a revenue increase of 90 percent, a .9 to 2.8 percent decrease in loads by 1994 does appear to be small. However, as stated in the preceding paragraph on page IV-67 of the RDEIS, BPA's power costs average only about 37 percent of utilities' total costs. In other words, rates for each utility will not increase by 90 percent, but by some amount based on the percentage of BPA's power costs to total costs.

BPA's projected response to the increase in the price of electricity is based on elasticity models of the residential, commercial, and industrial sectors. BPA's estimates fall within the range of electricity price elasticity estimates that have been determined through studies of these sectors.

A final point should be made regarding consumers' response to electricity price increases. Utility rates in the Pacific Northwest tend to make up a smaller percentage of the total budget than in other areas of the country. As a result, price increases in this region would likely have less effect on electricity demand than in other regions to the extent that electricity costs remain a relatively small portion of consumers' overall budgets.

LETTER NO. 55

U.S. Nuclear Regulatory Commission

No response required.

LETTER NO. 56

Tennessee Valley Authority

No response required.

LETTER NO. 57

Idaho State Historical Society

Letter No. 57, Comment No. 1

We agree with the statement involving siltation and have made the change in the text. The wave action impact was described in paragraph 5 on page IV-23 of the Revised Draft EIS so no further explanation was felt necessary.

The answer to the question posed is no. We don't expect any substantial impact from expansion of existing facilities.

Letter No. 57, Comment No. 2

Because impacts to archeological resources are highly site-specific and can usually be avoided or mitigated, they were not included in the generic comparison of resources. Additionally, and as stated on page IV-334, "Because the BPA proposal and alternatives are at the policy level, there will be no expenditure of funds having an effect on National Register and eligible properties resulting directly from a decision between the proposal and alternatives. Subsequent projects carrying out the policies in the proposal or alternatives may affect these properties and these effects will be taken into account when these subsequent projects are proposed."

Letter No. 57, Comment No. 3

It should be reemphasized that the "one-utility" concept is the basis of evaluation in the Role EIS. Under this concept the degree of cooperation/coordination has a direct relationship with system efficiencies. As discussed in the RDEIS, Alternatives 3 and 4 would have a higher system efficiency resulting in fewer transmission facilities which would in return minimize the impacts to archaeological resources. Alternatives 1 and 2 would have an opposite effect that could lead to more individual transmission facilities and more impacts to archaeological sites. The reason a comparison of impacts to archaeological resources resulting from the proposal and alternatives is not explicitly included is because it is not believed to be a significant issue at a programmatic level. The previous response also addresses this issue.

Letter No. 57, Comment No. 4

The question of simply who is going to construct electrical facilities, Federal or private, is not the real issue addressed in the Role EIS. Rather, the issue from BPA's viewpoint, and presumably from that of the region, is the number of facilities to be built and how institutional arrangements are likely to influence these system needs.

LETTER NO. 58

State of Utah; Division of Policy and Planning
Coordination, Intergovernmental Relations Section

No response required.

LETTER NO. 59

U.S. Department of Commerce; National Oceanic and
Atmospheric Administration; National Marine Fisheries Service

No response required.

LETTER NO. 60

Lane Council of Governments; Regional Clearinghouse
Review and Comment Conclusion

No response required.

Attachment C

BPA'S EVALUATION
OF
THE NATURAL RESOURCES DEFENSE COUNCIL'S
"ALTERNATIVE SCENARIO"

BPA EVALUATION OF THE ALTERNATIVE SCENARIO

Introduction - The NRDC Scenario generally performs a useful function. In a well-written, well-documented report, it introduces a scenario that serves to focus on options that are open to regional decisionmakers for shaping the region's energy future in an "alternative" way. By making all of its assumptions explicit, it permits reviewers to evaluate both in detail and in general how the Scenario is constructed, how sensitive it might be to changes in assumptions, and what implementation measures might be necessary to make the Scenario be realized.

BPA is following an end-use approach in the preparation of its own assessment of the regional potential for electricity conservation. A very detailed analysis of the end uses of electricity will reveal areas where conservation potential exists, and programs focusing on those areas can be better designed and monitored. BPA's conservation assessment will be completed within 2 to 3 months, and when finished, it will provide a useful and interesting comparison of results with the NRDC Scenario. This evaluation of the NRDC Scenario was able to draw upon the preliminary work done for that conservation assessment, and occasional references are made to that assessment which is now being drafted.

Both the NRDC Scenario and BPA's forthcoming conservation assessment provide useful detail and analyses of issues, but it is also important to support the point made by NRDC in the Scenario that ". . . we do not recommend that regional decisionmakers rely solely on a single scenario of the present type. Rather, a range of detailed scenarios should be constructed to understand the advantages, risks, and costs associated with different possible electrical energy futures in relation to an innovative array of policy options" (p. 18).

General Evaluation - The first major concern in our evaluation of the Scenario lies with the methodology used by NRDC. The Scenario claims that it "includes an analysis of each major 'end use' of electricity in the residential, commercial, manufacturing, and agricultural sectors" (p. 16). End-use analysis, as alluded to in the description of the Scenario above, works by adding together electricity demands from "the bottom up" in each sector. This approach requires a prodigious amount of data about those end uses of energy. More is known about the residential sector, and the end-use methodology in the Scenario was fairly successful there. In the other three sectors, particularly the commercial and industrial sectors, this methodology had to be abandoned because the required end-use data was not available. Instead of a "bottom-up" approach, the Scenario constructed a baseline forecast in those sectors by using a series of mostly arbitrary assumptions, and then subtracting from that baseline forecast various percentages in different subsectors that are attributed to conservation. In the industrial sector, detail is lacking about what conservation measures are accounted for within those percentages.

The significance of this alteration in the end-use approach lies in the fact that the independent baseline forecast was much lower than the PNUCC forecast against which the Scenario was being compared. About one-third of the difference between the Scenario and the PNUCC forecast seen in Figure 1 is attributable to this different implicit baseline forecast included in the Scenario. Two serious reservations exist here: First, as pointed out in the detailed comments on issues, the assumptions used by NRDC in developing the baseline are in many cases arbitrary and not related to any statistically observable trends; second, since the baseline is so low, we must wonder how much conservation is already embedded within it, so that subtracting additional conservation may prove to be at least partially double-counting.

The second major issue of the evaluation concerns whether all the identified conservation measures in the Scenario are technically feasible. For the most part, we agree that the measures are technically achievable with today's technology. However, there are two significant items with which we disagree. For existing large office buildings, the Scenario claims that retrofitting can save 83 percent of the energy used, and our analysis does not show that to be feasible, since 95 percent of the space heating demands would have to be conserved in order to achieve the Scenario's figure. In the aluminum industry, NRDC cites studies showing a potential 40 percent improvement in energy efficiency, but other studies dispute that claim from a technical perspective, indicating that the technical limit is probably closer to 30 percent.

The third area of major focus lies with the NRDC assertion that the identified measures are cost effective. We have concluded that the Alternative Scenario does include an array of conservation and renewable resources that are cost effective when compared against the costs of new electricity generation. As such, full implementation of those measures would result in lower costs to the Northwest, although we were unable to estimate how much could be saved in the next 15 years.

There were several instances, though, where BPA's preliminary analysis indicated that individual measures discussed in the Scenario were not cost effective. Although NRDC proposes that all pre-1976 homes be retrofit up to a ceiling insulation level of R-37, our preliminary analyses indicate that it will not be cost effective to increase the ceiling insulation levels of homes that already have about R-19 or more. Next, depending on assumptions made about insulation levels in the house, our preliminary studies also found that the cost effectiveness of electric heat pumps is doubtful. Third, the Rocket Research Corporation study indicated that only about half of the industrial cogeneration assumed in the Scenario is cost effective. And finally, because industrial conservation measures are not enumerated in detail, it is not possible to assess the cost effectiveness of the assumed conservation potential in the industrial sector.

The fourth area of major concern addressed in the evaluation is whether the implementation measures promoted by NRDC can result in the realization of the Scenario's results. Because no one can foretell the future with certainty, and because the Scenario is just that--a scenario that depicts one of many possible outcomes--we cannot comment extensively on this issue. We do have serious reservations, though, about whether the large number of government and utility programs will be initiated as outlined. The problems inherent in getting conservation investments made in the millions of homes, businesses, farms, and factories of the Pacific Northwest should not be underestimated. There are, in many cases, significant economic, institutional, and social barriers to be overcome for that to occur, particularly in the time frame indicated in the Scenario.

To summarize: (1) We have found serious fault with the methodology used in the Scenario, and primarily because of this, we place little faith in its numerical results, particularly in the commercial and industrial sectors. (2) For the most part, the measures included in the Scenario are technically feasible. (3) On the whole, the bulk of the conservation measures advocated in the Scenario appear to be cost effective. (4) We have reservations about the feasibility and potential success of the implementation measures.

We believe the Scenario is valuable as an initial effort at identifying areas of conservation potential and for initiating a discussion of policy options that can help realize that potential. Our technical analysis of the Scenario's measures has served to reinforce our belief in the basic BPA policy that conservation is the cheapest and quickest way to help solve the region's electricity problems. To use the Scenario as a planning document, however, is another matter, since assessments of the rates of adoption of conservation measures (what will be) must be done independent of goals (what should be). Planning, with appropriate readiness for contingencies, must be based upon beliefs of what will happen, not what could or should happen.

OVERVIEW

Issue: NRDC points out the environmental advantages which will be realized by avoiding the "Central Station Scenario" in favor of the Alternative Scenario (pp. 6, 111).

Response: In discussing future resource options or "scenarios," it should be noted that the probable outcome for the Pacific Northwest in terms of resource development will be a mixture of both conventional and unconventional resources. However, the Alternative Scenario seems to imply that the choice facing the Pacific Northwest is either that proposed by NRDC or the central station scenario. We feel it is inappropriate to characterize impacts absolutely or to present "all or nothing" comparisons of alternative scenarios and their impacts.

Additionally, as presented in Chapter IV, the Revised Draft Role EIS, unconventional or renewable resource development is not without its environmental impacts. As demonstrated in Chapter IV B, particularly in Tables IV-33, IV-35, and IV-42, unconventional resource development can involve substantial impacts principally involving land use, water consumption, air emissions, and thermal discharges.

Issue: In a general discussion of the methdology used in the Scenario, it is stated that an end-use approach is used. Several advantages of this approach are claimed, although it is not suggested that econometric analyses could not be a useful supplement to the end-use methodology (pp. 16-18).

Response: An end-use approach can be extremely valuable in analyzing a great many issues that are not capable of analysis by other methodologies. Such issues include weatherization retrofit programs, appliance efficiency standards, solar water heating, and other conservation efforts. Utilities and other energy analysts recognize the value of this approach (e.g., EMF, 1980, p. 35; Crow, 1979, p. xi). The PNUCC Econometric Model has incorporated an end-use approach into its residential sector (PNUCC, 1980, p. 16), and BPA has acquired and operates three separate end-use forecasting models for analytical purposes (Hirst and Carney, 1978; Isaak and Wilson, 1979; Cohn, et. al., 1980).

It must be pointed out, though, that NRDC was only partially successful in creating an end-use scenario. Rather than building up the total energy consumption from a detailed assessment of each energy end-use, in three of the four sectors (commercial, industrial, and agricultural), NRDC generated an independent baseline forecast from which they subtracted a percentage attributable to energy conservation efforts. The significance of this alteration in the end-use approach lies in the fact that the independent baseline forecast was much lower than the PNUCC forecast against which the NRDC Scenario was being compared. In fact, in its evaluation of the 1977 NRDC Scenario, TRW, Inc., discovered that approximately half of the difference between that scenario and the 1976 PNUCC forecast could be attributed to this before-conservation baseline forecast (TRW, 1977, pp. 1-7). The proportion attributable to this difference is smaller when comparing the 1980 Scenario and PNUCC forecast, because the two are not as far apart as was the case in 1977.

The major point to be made here is that an end-use approach can be a useful supplement to existing methodologies for forecasting future energy consumption, but data restrictions currently limit its usefulness. BPA is involved in several surveys that will obtain the data necessary for end-use analysis, and when that information is available, scenario analyses will become much more reliable and valuable.

Issue: NRDC states that "since 1976, BPA has added almost one million people to its 1995 population projections for the West Group Area" (p. 19).

Response: The actual increase between BPA's 1976 and 1979/80 population forecasts for 1995 was 567,000. The detailed listing of the forecasts is as follows:

	1995 Population	
	1976 Forecast	1979/80 Forecast
Washington	4,583,200	4,876,500
Oregon	2,944,400	3,165,200
Idaho	1,163,300	1,205,400
Western Montana	285,700	296,500
Total	8,976,600	9,543,600

Apparently, NRDC was comparing BPA's 1979/80 forecast for the year 2000 (total population: 9,976,200) with the 1976 forecast for the year 1995.

Issue: NRDC believes that BPA's population projections are too high, citing other projections which are lower as evidence (pp. 19-20).

Response: It is not true that BPA's projections "significantly exceed" the population projections prepared by agencies within the three Northwest states. In fact, the differences for the sum of three states' projections amounts to less than two-tenths of one percent, as outlined below:

	BPA	State Agency (See References)	Difference
Oregon	3,165,200	3,142,000	0.73%
Washington	4,876,500	4,849,000	0.56
Idaho	1,205,400	1,239,000	-2.79
TOTAL	9,247,100	9,230,000	0.18%

NRDC also cites the projections of the Bureau of Census Series IIA, B, and C, which are exceeded by BPA's 1995 projections by 9, 14, and 18 percent, respectively. It is BPA's contention that these Census projections for the Pacific Northwest states can be afforded no credibility. The following table can be used to illustrate the reasons for this belief.

First, notice that the Bureau of Census Estimates of population for the year 1979 in every case exceed the Bureau of Census Projections of population for the year 1980. It is probable that the total deficiency between the 1980 Bureau of Census Projections and the 1980 Decennial Census for the three states will be in the neighborhood of 425,000 to 600,000, depending upon the Bureau of Census Series. With the 1980 Census Projections so badly under-forecast, the 1995 Projections are undoubtedly also seriously off the mark.

Close examination of the table reveals several other serious inconsistencies. Two examples: (a) The Series IIC figure for Oregon in 1995 (2,602,500) may be only slightly higher than is likely to be reported in the 1980 Decennial Census; it is almost certain to be exceeded by the year 1981. (b) The Series IIB 1995 projection for Washington (4,060,200) is just 120,000 higher than what is likely to be reported for that state in the 1980 Census; it is likely that this 1995 projection will actually be exceeded by the year 1982.

COMPARISON OF CENSUS 1979 ESTIMATES, CENSUS SERIES IIA, B, AND C PROJECTIONS, AND BPA PROJECTIONS
(all numbers in thousands)

	Oregon	Washington	Idaho
Census Series IIA 1980 Projections	2,437.2	3,783.8	866.2
Census Series IIB 1980 Projections	2,437.3	3,655.6	893.0
Census Series IIC 1980 Projections	2,355.4	3,696.8	857.4
Census 1979 Estimates	2,527.0	3,926.0	905.0
BPA 1980 Projection	2,575.5	3,929.4	935.4
Census Series IIA 1995 Projections	2,932.8	4,550.7	1,030.0
Census Series IIB 1995 Projections	2,935.0	4,060.2	1,133.5
Census Series IIC 1995 Projections	2,602.5	4,190.8	1,016.9
BPA 1995 Projections	3,165.0	4,876.0	1,205.0

Issue: NRDC uses 1975 as the base year of analysis (p. 22).

Response: The use of 1975 as the base year of analysis reduces the usefulness of the Scenario for system planning purposes. Conclusions drawn about energy requirements in 1985 and 1995 under the Scenario are misleading. The "vigorous efforts . . . to increase energy efficiency of energy use" (p. 22) assumed in the Scenario to have been in effect since 1975 have not occurred as extensively as supposed. Thus we have the curious situation of actual commercial sector electricity usage in 1978 exceeding the 1985 NRDC scenario value (2216 Average Megawatts Actual compared to 2137 Average Megawatts in the NRDC Scenario) (Table 1, p. 24). While it may be possible that commercial sector electricity use will decline between 1978 and 1985, the continuing trend from 1976 to 1978 of increasing use reduces the confidence one might have in the belief that a decline will occur during that future time frame.

Another example is in the residential sector, where statistics compiled through the National Association of Home Builders for the Pacific Northwest states show that insulation levels in new homes built since 1975 haven't been up to the NRDC-assumed levels. For single family dwellings built from 1976-1978, the average R-value in ceilings has been approximately R-24, in walls R-12, and in floors R-14, (Housing Industry Dynamics, 1979). This compares to the post-1975 NRDC levels of R-37, R-19, and R-19, respectively.

Issue: In the Scenario's projections of net firm generation resources, no provision is made for energy reserve requirements (Table 2, p. 27).

Response: The need for energy reserves is for the principal purpose of preparing for contingencies of exceptional growth rates in energy requirements or slippages in thermal plant schedules. The West Group Forecast includes energy reserves equal to a half year's growth of utility loads (BPA, 1977, p. II-16, 17). Even in the absence of load growth (which occurs in the NRDC Scenario from 1985 to 1995), there should be some energy reserves to allow for long-term thermal plant forced outages. By eliminating energy reserves, NRDC has in effect transferred that contingency to its calculation of the resource surplus.

RESIDENTIAL SECTOR

Issue: Reductions in residential heating requirements were calculated from implementation of conservation measures specified in the SOM study as Strategy 6 (pp. 34-35).

Response: The measures in SOM's Strategy 6 were developed for four prototypical homes in the Pacific Northwest. They were designed to yield the total space heating usage for the region when multiplied by the housing stocks and to reflect current housing practices. However, the recent Pacific Northwest Residential Energy Survey indicates that many of SOM's proposed conservation measures have already been undertaken.

SOM suggests lowering the thermostat in homes from 70 degrees to 68 degrees. However, the residential survey shows that the average daytime temperature in single family homes is 67.7 degrees, and 67.2 degrees in multifamily homes. SOM also suggests that a semiautomatic night thermostat be installed, which will lower the temperature from 70 degrees to 62 degrees. Again, the residential survey shows that this measure has, in effect, been fully implemented. The average nighttime temperature in single family homes is 62.9 degrees and 63.9 degrees in multifamily homes.

The SOM study also assumes that pre-1974 dwellings have no weatherstripping or caulking, and no dwellings have storm windows. The survey shows that from a third to half of the homes in the Northwest have already implemented these measures.

Also, as a technical matter, NRDC's recommendation to install semi-automatic thermostats cannot be accomplished on many or most homes because ceiling cable or baseboard electric systems have thermostats in each room. To our knowledge, no inexpensive effective device has been developed, or is being worked on, which will setback different thermostats in the same house.

Thus, the calculations in the SOM study used an inaccurate base, and this should require changes in the NRDC calculations as well, at least for the 1975 base year shares between space heating and appliances.

Issue: NRDC recommends that walls in existing dwellings be insulated with 3-1/2" of U.F. foam (where insulation does not already exist) and insulate walls in new dwellings to 5-1/2" (R-19) (p. 35).

Response: This recommendation is questionable on two counts. First, U.F. foam is a suspect material at this point. It is a source of formaldehyde gas during a very long curing process and is under investigation by the Consumer Protection Safety Commission. George Tsongas (1979, p. 11) also noted another significant problem with the material: "It should be pointed out that such shrinkage and cracking of U.F. foam can have a considerable effect on the thermal performance of the walls insulated with foam." He then goes on to note that HUD and the Canadian Government have derated the insulating value of the foam by 28 percent and 40 percent repectively (33 percent and 54 percent repective increases in heat loss).

With regard to blown type materials (i.e., cellulose and mineral fiber), the Tsongas report notes little shrinkage problems. Significant problems involving fire resistant quality of insulation were discovered. Dr. Tsongas concludes by stating: "Pending further studies of the question outlined above, however, the energy and cost effectiveness of retrofitted wall insulation can appropriately be considered an open question." And further that its installation should continue to be viewed as " . . . a relatively low priority conservation technique . . . ."

In new dwellings a building code change may be required for 6" walls to accommodate R-19, or R-19 may be achieved through the use of styrofoam sheathing.

<u>Issue</u>: It is assumed that floors be insulated to a level of R-19 (p. 35).

<u>Response</u>: We agree with this measure as being technically feasible and practical. We would add the statement should include crawl space and basement perimeter insulation also.

<u>Issue</u>: NRDC suggest that storm windows be installed in existing dwellings and double glass windows in new dwellings (p. 35).

<u>Response</u>: We agree with this measure as being technically feasible and practical. The Pacific Northwest Residential Energy Survey indicated that 36 percent of dwellings had all their windows with double glazing or storm windows, and another 9 percent have some of their windows with double glazing or storm windows.

<u>Issue</u>: The Scenario calls for retrofitting all single family dwellings built before 1976 with insulation to levels of R-37 in the ceiling, R-11 in the walls, and R-19 in the floor (p. 35).

<u>Response</u>: In a cost-effective analysis done for BPA's regional conservation assessment, preliminary results indicate that it may not be cost effective (at marginal cost prices) to retrofit every house in the region to those levels, depending on the location of the house and the existing levels of insulation. For example, it does not appear to be cost effective for a home in Portland with R-19 insulation in the ceiling to increase that insulation to a level of R-38, but such a retrofit may be marginal in Spokane. Similarly, the preliminary analysis shows it is marginal for a Portland home with R-11 ceiling insulation to go up to an R-38 level, but in Spokane it does appear to be cost effective. These limitations will have a relatively minor effect on the total space heating conservation potential.

Issue: NRDC used BPA's most recent projections of total households in the West Group Area (pp. 36, A2).

Response: BPA puts out a forecast of population and households for the entire Pacific Northwest; Washington, Oregon, Idaho, and Western Montana. Of the Northwest, the West Group Area incorporates all the population of Washington, 97 percent of Oregon, 36 percent of Idaho, and 70 percent of Western Montana. In using the BPA household forecast, NRDC did not adjust the data from the Pacific Northwest to the West Group Area. This has resulted in NRDC using population and household forecasts for the West Group Area which are approximately 10 percent higher than the actual forecast for that area. For example, the number of households used by NRDC for 1995 is 3,901,112. This corresponds to the BPA forecast for the entire Pacific Northwest. The number of households projected for 1995 for the West Group Area is 3,522,456.

The use of this higher household projection results in a significant overstatement of the residential load in the West Group Area.

Issue: NRDC projects that by 1995, 25 percent of all single family homes will have heat pumps, along with 7 percent of all multifamily units (p. 37).

Response: In a preliminary analysis done for the BPA conservation assessment, it was found that cost effectiveness of heat pumps depends on levels of insulation in the home and on the climate. The large initial investment of approximately $1000 per ton of capacity, plus $60 per year for maintenance (OSU, October 1979; Gordian Associates, Inc., April 1976, p. 102), make it difficult for the heat pump to pay for itself. The SOM study came to the same conclusion (p. 84).

Given this preliminary analysis, it seems doubtful that retrofit and penetration rates for heat pumps will be as high as indicated by the NRDC Scenario. Only 2.4 percent of the single family homes existing in 1979 had heat pumps. It is possible, though, that some heat pumps may be installed as a result of restrictions on new electric resistance space heat connections. The assumption used in the BPA conservation assessment is that 10 percent of the single family dwellings would have heat pumps by the year 2000, with none in multifamily units. This allows for those homes in which they are already installed, and for a modest number of homeowners who undertake the project regardless of the cost effectiveness. The result is that, whereas savings are 2,390,000 megawatthours in 1995 by the NRDC assumption, they would only amount to 847,783 megawatthours under the BPA assumption.

Issue: The Scenario assumes that 20 percent of all single family homes will have passive solar heating systems by 1995 (p. 37). This requires a penetration rate of passive solar in new homes increasing from 0 in 1980 to 40 percent in 1985 to 80 percent in 1995 (p. A5).

Response: The feasibility of such a projection seems highly questionable. Given the magnitude of the investment involved and the wide variety of public tastes in home architecture, such high saturation rates appear doubtful with either a mandatory or large subsidy program.

This implementation difficulty is well illustrated by the lack of government programs to date which deal with passive solar--in contrast to the plethora of incentives offered for conservation and active solar. The question appears to involve a legitimate institutional barrier: should a new house with large stone/brick storage media, specially designed roof overhangs, and shade screens (p. 49), qualify for an energy tax credit? Or is this part of the owner's normal design preferences for which he/she is trying to collect financial benefit from the government? Federal and State IRS officials tend to take a fairly restrictive view of incentive programs to encourage such measures, regardless of what their governmental energy couterparts may think. In any event, a passive solar incentive program would require thousands of discrete judgments about whether government money was being used for a legitimate energy purpose. Given the sheer number of such judgments required to achieve 80 percent market penetration by 1995, this assumption appears unwarranted.

Issue: Installation of a heat pump will reduce a dwelling's space heating requirements by 50 percent (p. 38).

Response: A similar assumption has been employed in the BPA Conservation Assessment. The literature varies widely on heat pump usages and savings, with few, if any, metering studies. However, most of the literature ranges around savings of 50 percent (A.E.D.C., May 1980 p. A-10; ORNL/DOE, May 1979).

NRDC ignores the added electrical requirements for air conditioning that would be required in the residence because of the presence of heat pumps. Using a degree day estimate, the air conditioning load would be increased and would utilize about a 15 percent increase in electrical energy. Therefore, a residential heat pump in a Northwest climate has a net effect of reducing the electrical use for space conditioning (both heating and cooling) to about 35 percent rather than 50 percent.

Issue: In order to estimate the peak load in the residential sector, NRDC calculated the contribution to system peak of each major end-use as a ratio of the peak-to-average energy use. For example, the total contribution to the system peak from residential electric space heating was calculated by multiplying the total energy consumed by electric space heating by 2.98 MW/average MW (pp. 39-40, A9, A22). Ratios for space heat and water heat increase slightly over time, while the ratios for all other appliances remain constant.

Response: There are significant problems with the data used to estimate the peak-to-energy ratios. First, the ratio for the space heating load was reported to be based on BPA estimates for 1973-74, while no references are provided for appliance ratio estimates. To our knowledge, no hourly metering studies of individual appliances have ever been done in the Pacific Northwest. The derivation of the 1985 and 1995 ratio estimates are completely undocumented.

There are actually three pieces of information required for each appliance in order to estimate the system peak-to-energy ratios. The first is the daily load profiles during the winter peak of the diversified kW demand of each appliance. Nationwide, many studies have been done on that topic and have been documented in Reznek, 1978. The Pacific Northwest has a particular problem in that the winter daily peaks occur almost equally at 9 a.m. and 5 p.m., while the daily load profile of given appliances can vary greatly during those two time periods. For example, one estimate of Seattle's electric space heat load profile indicated that resistance heating had a diversified peak of 8.15 kW/unit at 9 a.m. on the peak day but only 5.1 kW/unit at 5 p.m. (Hittman, 1980, p. III-10). Obviously, the selection of one of these values over the other will have a tremendous impact on the peak forecast using this methodology.

The second step is to select the value for the diversified peak from those daily load profiles. Actual metered data from several utilities around the country indicate a large amount of variation in these values. For example, for a 5 p.m. peak, Hittman's survey of these studies indicated the following ranges of diversified kW peak for these appliances: electric space heat - 2.90 to 7.67 kW/unit: water heater - 0.40 to 1.05; clothes dryer - 0.14 to 0.375. These ranges indicate a great deal of uncertainty.

The table below compares NRDC's values with values calculated from data in Fitzpatrick, 1979, p. 5-7, and it illustrates the wide diversity of estimates.

Diversified System Peak-to-Energy Ratios, 1975

	NRDC	Long Island Lighting Co.
Refrigerator	1.00	1.25 frost free 1.53 manual defrost
Freezer	0.09	0.94
Space Heat	2.98	NA
Water Heat	2.21	1.21
Color TV	3.19	2.28
B & W TV	3.19	1.86
Range/Oven	7.33	5.48
Clothes Washer	0.47	2.55
Clothes Dryer	0.47	1.76
Dishwasher	0.47	2.90
Lighting	0.97	1.75
Air Conditioning	0.47	NA
Other	0.47	2.92

NA - not applicable; summer peaking utility.

The third step is to calculate the ratios based on estimates of the annual kWh use per appliance. NRDC has included estimates for this, based on a University of Texas study, but as is pointed out elsewhere, there is also a significant degree of uncertainty surrounding those estimates.

When these three sources of uncertainty are combined together to produce a ratio of peak to energy, that resulting ratio will have such a large amount of uncertainty that no confidence can be placed in the results. In sum, the quality of the available data does not permit the use of this methodology for the Pacific Northwest region.

There are two technical asides which probably should be made as well. First, it would be expected that the ratios would increase over time, because appliance efficiency improvements can be expected to result in larger savings in energy than in diversified peak demand, at least for a winter-peaking utility system (U.S. DOE, June 1980, p. 5-43). Second, NRDC included a peak-to-energy ratio of 0.47 for air conditioning, when it should obviously be zero since there is no air conditioning during the winter peak period.

Issue: Furnace efficiencies for fossil fuels (natural gas and fuel oil) are assumed to be 50 percent efficient in 1975, increasing to 60 percent in 1985 and 70 percent in 1995 (p. 40).

Response: The historical figure given of 50 percent efficiency in 1975 is too low. Actual furnace efficiency tests concluded that the national average for gas furnaces was somewhere between 55 and 65 percent, while oil furnace efficiency was about 55 percent (Hise and Holman, 1975, p. 1; New York Testing Laboratories, 1967). The projected efficiency levels for 1985 and 1995 may well prove to be close to the mark, however. The Department of Energy has recently announced proposed appliance efficiency standards for eight major appliances, including furnaces. These standards specify that gas forced air furnaces should be 65 percent efficient by 1981 and 81 percent by 1986; oil furnace standards are 75 percent by 1981 and 80 percent by 1986 (45 FR 43976). The large existing stock of gas and oil furnaces must have their current operating efficiencies improved, but annual maintenance and some retrofit options should be able to increase the efficiencies to the assumed levels.

Issue: NRDC cites a study that claims a 90 percent efficiency rate is possible for fossil fuel central heating furnaces (p. 40).

Response: Popular Science magazine is used here as a reference by NRDC. However, the conclusions reached as a result are not necessarily supported by the articles referenced. The high efficiency heating plants discussed in the articles are oil and gas fired boilers. The articles note that tests have not yet been conducted on furnaces. In this context, a boiler is defined as a device that heats water and a furnace one which heats air. However, in the Pacific Northwest the vast majority of central fossil fuel heating plants are furnaces -- not boilers -- in residential applications. Therefore, the conslusions that the results are applicable to the Pacific Northwest are suspect.

Many of the highest effective devices discussed are still in the R&D stage of development. As such, it can be assumed that considerable time and effort must still be expended before they can be brought to the market and that some of them will not prove to be feasible for commercial production. For instance, Popular Science states: "But making a commercially viable pulse-combustion furnace is trickier than making a boiler. The problem: noise. The same noise that gave the buzz bomb its name also occurs in a pulse-combustion heating system."

Such problems are not insurmountable; however, they are typical of state-of-the-art product development and can be expected to slow the introduction and acceptance of new products into the market place. As a result, energy savings in the region will be affected.

Issue: The projected central station space heating requirements for the Scenario are 16,230,000 megawatthours of electricity in 1995 (pp. 42, A8).

Response: The Official West Group Forecast of residential space heating, as disaggregated by the Oregon Department of Energy's residential end-use model, ENDUSE-2, is 19,412,243 megawatthours in 1995. In an analysis done for the BPA Conservation Assessment, it was concluded that approximately 2,186,000 megawatthours would be saved by retrofitting existing single family homes with a mandatory program similar to the one used in the SOM study, Strategy 6. Another 3,827,000 megawatthours can be saved in space heating for new homes, when built to standards which reduce average usage to about 6000 kilowatthours per year. With savings from heat pumps of 869,000 megawatthours, the total space heating requirements for the West Group Area can be reduced to 13,711,000 megawatthours in 1995. This is considerably below the NRDC Scenario's 1995 space heating requirements.

The difference between the two results appears to be the result of several factors. The first is the discrepancy in population forecasts used, as described earlier. If the lower projections used in the BPA Conservation Assessment had been used by NRDC, the difference would have been significantly less. Another factor is that the NRDC scenario uses the prototypical homes and space heating results of the SOM study, which were based on space heat usages forecast for the region by BPA in 1975-76. Since that time, the forecasts have been reduced and so the SOM base case, with no conservation, is very high, which means the NRDC scenario is not computing the conservation savings from an accurate base.

Issue: Although not used directly by NRDC, DOE's Building Energy Performance Standards are cited as an example of how residential energy efficiency will continue to improve in future years (pp. 46, 164).

Response: The proposed Building Energy Performance Standards do indicate a general tendency to move toward more stringent standards. However, it is also useful to consider the recent difficulties that the proposed standards have encountered. The U.S. Senate has voted to delay the implementation by up to 2 years (from 1981 to 1983). In addition, BEPS will not affect all new buildings. If no sanctions are imposed by the Congress, then only FHA, VA, and FMHA mortgage-insured buildings and Federal buildings will need to comply with the Standards; thus, the minimum residential and commercial compliance rates would be 15 percent and 6 percent, respectively. If sanctions are implemented, then buildings which use either construction or mortgage loans from a Federally regulated private financial institution, a Federal mortgage insurance program, or a Federal secondary mortgage company must be in compliance with the Standards; 66 percent of all buildings would then be affected by the Standards (U.S. DOE, March 1980, p. 3.18). While this does not affect the Scenario's projected savings, it is another real world illustration of the political difficulty experienced when implementing mandatory-type programs.

Issue: Total electricity requirements for appliances are dependent upon estimates of annual kWh consumption for each type of appliance (pp. 50, A13, A14).

Response: In assessing the portion of the residential load attributable to appliance use other than space heating, assumptions must be made concerning individual appliance use. These assumptions must not only consider the first year of the forecast, but all years within the forecast. NRDC adapted the University of Texas estimates of future appliance energy consumption for California to the Northwest. While these estimates for the most part could be judged as reasonable, they are not the only ones available. Many studies on appliance use have been conducted by many different researchers. Each study has resulted in a different estimate for appliance use. This would indicate differences in measurement procedures, either statistical or mechanical, and/or differences in appliance utilization, thereby increasing (or decreasing) annual appliance use estimates. In the following tables, estimates from different studies have been listed, as well as the 1975 estimates used in the Scenario.

ANNUAL UNIT CONSUMPTION

Study	Region	kWh/Year
	Water Heating	
Dole (1975)	Pacific	4095
Socolow (1978)	New Jersey	8000
Electric Energy Assn. (1976)	U.S.	4219
Smith (1976)	U.S.	3876
NRDC	PNW	4442

ANNUAL UNIT CONSUMPTION (cont.)

Study	Region	kWh/Year
	Refrigerators	
Dole (1975)	Pacific	1134
Electric Energy Assn. (1976)	U.S.	1137
Smith (1976)	U.S.	1200
Harper, et. al. (1978)	West	1572 (frost-free)
		1537
NRDC	PNW	672
	Range/Oven	
Electric Energy Assn. (1976)	U.S.	1175
Harper, et. al. (1978)	West	664
Smith (1976)	U.S.	1200
Dole (1975)	Pacific	1200
NRDC	PNW	1108
	Clothes Dryer	
Harper, et. al. (1978)	West	850
Dole (1975)	Pacific	996
Smith (1976)	U.S.	840
Electric Energy Assn. (1976)	U.S.	993
NRDC	PNW	916
	Dishwasher	
Dole (1975)	Pacific	400
Harper, et. al. (1978)	West	149
Electric Energy Assn. (1976)	U.S.	363
Smith (1976)	U.S.	348
NRDC	PNW	335
	Freezer	
Smith (1976)	U.S.	1056
		1524 (frost-free)
Harper, et. al. (1978)	West	1336
Dole (1975)	Pacific	1395
Electric Energy Assn. (1976)	U.S.	1195
		1761 (frost-free)
NRDC	PNW	1103

As seen in the tables above, NRDC estimates from the University of Texas study are usually bracketed by estimates or actual metered data from other studies. However, there is a wide variation exhibited, and the selection of one set of estimates over another could have a large impact on the Scenario's results. There is one significant exception: NRDC's estimate for refrigerators appears to be significantly out of line. If NRDC had used an estimate of (for example) 1,272 kWh/year instead of 672, that would make a difference of 163 average MW in 1975.

One category of residential use that is not covered in the above tables is the area of "miscellaneous" usage. Miscellaneous use would encompass all the residential uses not specifically mentioned earlier, such as kitchen countertop applicances, hair blowers, clocks, lawn and garden equipment, shop tools, etc. Very few, if any, studies have been done in an attempt to quantify miscellaneous use. Therefore, estimating miscellaneous use is a very subjective and arbitrary exercise. A comparison of appliance usages used in the scenario with those currently being used by BPA for a conservation assessment study can be seen in the following table. Most of the BPA base year values were obtained from a metered study conducted by Midwest Research Institute (Harper, et. al., 1977). The lighting estimate was supplied to us by Oregon Department of Energy, while water heat and miscellaneous estimates were obtained from the PNUCC Econometric Model. 1995 values for the BPA study were derived by either holding use constant or applying efficiency improvements assumed in PNUCC model inputs.

ANNUAL APPLIANCE USAGE
(kWh/year)

	NRDC		BPA	
	1975	1995	1979	1995
Water Heat	4442	3510	4296	3637*
Lighting	1662	1278	891	891
Refrigerator	672	693	1537	1537
Range/Oven	1108	987	664	597
Television			417	417
Color	464	248		
B/W	334	167		
Freezer	1103	965	1336	1336
Clothes Dryer	916	859	850	764
Clothes Washer	95	95	89	89
Dishwasher	335	251	149	111
Air Conditioner	1108	600	1200	1200
Miscellaneous	679	2030	1785	4085

*includes solar heating contribution.

For most of the covered appliances, there are not significant differences on usage estimates. However, for refrigerator, air conditioner, and miscellaneous use there is considerable disparity.

Issue: Total appliance energy use is also dependent upon the number of households owning particular appliances (appliance saturation) (pp. 51, A16).

Response: Assumptions concerning appliance saturation can be just as critical as those concerning applicance use. Higher saturation will result in larger forecasts, and vice versa. BPA staff have been able to rely upon data from the recently completed residential survey for base year saturation rates. Future saturation rates have been derived from several sources, including the PNUCC econometric model, ENDUSE2 model (Isaak and Wilson, 1979), and staff judgement. The table below is a comparison of base year and ending year saturations used in the Scenario and in the conservation assessment project. For the most part, NRDC's saturation estimates are somewhat lower.

APPLIANCE SATURATIONS
(percent)

	NRDC		Conservation Assessment	
	1975	1995	1979	1995
Water Heat	.8587	.9700	.856	.920
Lighting	1.0000	1.0000	1.000	1.000
Refrigerator	.9874	1.0830	1.143	1.190
Range/Oven	.8940	.9386	.945	.987
Television			1.450	1.540
Color	.5737	.9571		
B/W	.6633	.5000		
Freezer	.4726	.5792	.463	.670
Clothes Dryer	.6371	.7393	.695	.891
Clothes Washer	.7349	.8112	.766	.900
Dishwasher	.3922	.7181	.507	.631
Air Conditioner	.1558	.2861	.181	.275
Miscellaneous	1.0000	1.0000	1.000	1.000

Issue: By combining appliance use and saturation, NRDC is able to forecast electricity consumption for appliances (p. 52).

Response: By using the information provided in the previous two issues, in conjunction with the Scenario's assumption on number of households in the region, the following table was developed which shows the difference in projections of total appliance use between the Scenario and BPA's conservation assessment for the year 1995.

CENTRAL STATION APPLIANCE REQUIREMENTS
(1,000's of MWh)

	NRDC 1995	BPA 1995
Water Heat	12,651*	13,053**
Lighting	4,986	3,476
Refrigeration	2,929	7,135
Range/Oven	3,614	2,297
Television		2,505
Color	929	
B/W	326	
Freezer	2,182	3,492
Clothes Dryer	2,478	2,673
Clothes Washer	301	312
Dishwasher	704	273
Air Conditioner	670	1,287
Miscellaneous	7,919	15,936
Total	39,690	52,439

*Includes Heat Pump and Solar Contribution
**Includes Solar Contribution only

As the table indicates, the two projections are quite far apart. Closer inspection reveals that the main cause of the disparity lies in the assumptions of refrigerator use and miscellaneous use. These two categories make up almost the entire total difference in the projections. We feel that in the case of refrigerator use, the Scenario uses an unreliably low use. The only type of refrigerator with that low of a usage that we are aware of would be a small non-frost-free unit. That does not reflect the stock of refrigerators in existence in the region, according to the residential survey results. Miscellaneous use, on the other hand, depends so much on subjective judgment and opinion that we cannot either dispute or defend that used in the Scenario. On the whole, except for the two aforementioned differences the appliance usage section of the residential sector appears to be reasonable and acceptable. This analysis is being reviewed in light of the proposed efficiency standards for eight appliances (U.S. DOE, June 30, 1980), and it is probable that revisions will be able to reconcile many of the remaining differences.

Issue: For water heating, NRDC assumed cost-effective savings could be achieved from extra insulation jackets, shower flow restrictors, solar water heaters in new single-family residences, and heat pump water heaters in existing single family residences and new single family residences without solar water heating (pp. 55-57, A17, A18).

Response: We concur that these measures are cost-effective. In addition, NRDC has overlooked another significant measure for saving energy for water heating; turning the thermostat back to 140 degrees F for homes with dishwashers and 120 degrees F for homes without dishwashers. Studies have shown that from 4 to 10 percent in water heating requirments per residence can be achieved by this measure at no capital cost (Mutch, 1974, P. vi).

Issue: NRDC assumes that heat pump water heaters and solar water heaters each would reduce the water heating requirements of a residence by 50 percent (pp. 58, A18).

Response: BPA has assumed similar unit savings potentials. Estimates for solar in the Pacific Northwest and Oregon range between 65 and 80 percent (U.S. DOE and U.S. EPA, 1978; PGE, 1980; NEPP; 1977). In its conservation assessment, BPA has assumed 60 percent, which is on the conservative side of these estimates, but more optimistic than NRDC's. With respect to heat pump water heaters, BPA has assumed a 40 percent, rather than 50 percent, unit savings because of the possibility that in some or all installations the space heating system may have to replace some heat extracted by the heat pump to heat water.

Issue: Table A-13 of the Scenario (p. A19) summarizes NRDC's calculations of electrical energy savings from heat pump and solar water heaters (p. 58).

Response: BPA has not been able to replicate the values presented in the following table. The following table provides a comparison of the NRDC savings and the savings as computed by BPA using NRDC's input values. Note that in the case of both heat pump retrofits to pre-1976 single family dwellings and solar installations in post-1975 single family dwellings, BPA calculates savings several magnitudes larger than does NRDC, for both 1985 and 1995. However, even these large, computational, differences do not have a very significant effect on total water heating requirements.

Issue: NRDC assumes the following rates of adoption for heat pump and solar water heaters:

	Saturations (percent)		
	1975	1985	1995
Heat Pump Water Heaters			
Pre-1976 Single Family Dwellings	0.0	0.10	0.40
Post-1975 Single Family Dwellings		(0.10) 1/	(0.10) 1/
Solar Water Heaters			
Post-1975 Single Family Dwellings	0.0	01.0	0.40

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1. 10 percent of residences not built with solar water heaters are retrofitted with heat pump waterheaters 5 years after construction, beginning in 1981.

(From pp. 58, A17, A18)

Response: These assumptions are not too different from the ones which BPA made on its conservation assessment. NRDC has assumed that heat pump water heaters would be confined to retrofits in single family residences and solar water heaters restricted to single family new construction, but adds that both may be justified in multifamily dwellings, new or existing. Also, heat pump water heaters are cost effective in new single family residences.

ELECTRICAL ENERGY SAVINGS AND REQUIREMENTS FROM HEAT PUMP WATER HEATERS AND SOLAR WATER HEATERS 1/

	1985 As calculated by NRDC	1985 As calculated by BPA	1995 As calculated by NRDC	1995 As calculated by BPA
Energy Savings (10^6 kWh/yr.)				
Heat Pump Water Heater				
Pre-1976 Single Family Dwellings	93.314	279.910	406.354 2/	987.050 2/
Post-1976 Single Family Dwellings	58.770	10.989	95.290 2/	(95.290) 3/
Solar Water Heater				
Post-1975 Single Family Dwellings	33.700	109.887	129.400 2/	699.778 2/
	185.784	400.786	631.044	1,782.118 4/
Energy Requirements (10^9 kWh/yr.)				
Water Heater Electrical Energy Requirements	11.381	11.381 5/	13.282	13.282 5/
Energy Savings	-1.86	-.401	-.631	-1.782 4/
Net Water Heater Electrical Energy Requirements	11.195	10.980	12.651	11.500 4/

1/ Based on Table A-13 in NRDC Scenario (p. A19); BPA values were calculated from input values either provided directly by NRDC or interpolated by BPA from these values.

2/ Calculated according to general formula:

Saturation of Heat Pump or Solar Water X Saturation of Electric Water Heaters X No. of Dwellings X Average Annual per Usage Water Heater X Percent Savings per Heat Pump or Solar Water Heater

E.g.: Savings in 1985 from heat pump waterheater retrofits in pre-1976 single family dwellings :

$$.10 \times 0.9334 \times 1,602,797 \times 3742 \times 0.50 = 279.910 \times 10^6 \text{ kWh/yr.}$$

3/ This calcualtion was not attempted because it represents several iterations involving interpolations of housing stock and proportions there without solar water heaters. However, preliminary calculations are of the same order of magnitude.

4/ These values include NRDC's calculation for 1995 heat pump water heater retrofits in dwellings built 5 years earlier, beginning in 1981.

5/ Calculated according to general formula:

Saturation of Electric Water Heaters X Total Housing Stock X Average Annual Usage in Water Heater

Issue: The NRDC estimate of 1975 commercial floor space is for the Pacific Northwest (Washington, Oregon, Idaho, and Western Montana) rather than the West Group Area (pp. 62, B1-B3).

Response: As noted earlier, a significant part of Idaho's and Western Montana's population are not in the West Group Area. Overall the population of the West Group Area is about 90 percent of the population in the Pacific Northwest. BPA multiplied the identical 1975 commercial floor space estimate of 744 million square feet using the ratio of the 1975 commercial electricity sales in the West Group Area to sales in the Pacific Northwest to obtain an estimate of 675 million square feet of floor space for the West Group Area.

Issue: NRDC does not adjust Non-Basic and Federal Employment to the West Group Area (pp. 62, B1, B2).

Response: The NRDC employment estimates used to project rates of growth in commercial floor space are for the Pacific Northwest rather than the West Group Area. Recalculating the NRDC 1975 estimate of 2,187,500 by subtracting employment in counties of Oregon, Idaho, and Western Montana not in the West Group Area yields a West Group Area Non-Basic and Federal Employment estimate of 1,949,654, 10.9 percent lower.

Issue: NRDC states "Commercial energy use is assumed to increase in direct proportion to commercial floor space, which in turn is assumed to increase in direct proportion to the growth in total non-basic and Federal employment" (pp. 62, B1).

Response: These assumptions are not supported by available data. The NRDC assumption that "Commercial energy use is assumed to increase in direct proportion to commercial floor space" does not agree with a recent study for EPRI by Data Resources, Inc. This study used national data for 1963-1975 in a pooled time-series cross-section econometric analysis of commercial energy use. Their results indicate that commercial energy use increases at different rates for different fuels as commercial floor space increases. For electricity, the study estimates that a 1 percent increase in total floor space will result in a 1.18 percent increase in electricity consumption (Huntington and Soffer, 1979).

The NRDC assumption that commercial floor space "is assumed to increase in direct proportion to the growth in total non-basic and Federal employment" does not agree with national data, either. Commercial floor space increased at an annual growth rate of 4.2 percent while employment for the period increased at 3.7 percent (GE Center for Energy Systems, 1978; U.S.

Department of Commerce, various years). If these historic relationships hold, the results of these two studies imply that commercial electricity use will increase more rapidly than commercial sector employment. This implication is confirmed for the West Group Area. The rate of growth in total non-basic and Federal employment was calculated from BPA employment data for 1970 to 1975 to be 3.01 percent. During the same period, commercial electricity sales increased at a rate of 6.69 percent.

These NRDC floor space growth assumptions alone are probably responsible for the NRDC estimated decline in commercial electricity requirements from 16,940 MkWh in 1975 to 15,550 MkWh in 1995 (p. 68).

In BPA's commercial sector Conservation Assessment, floor space additions are projected using econometrically determined equations which relate floor space additions to the growth in population and real disposable per capita income. Although additional research is needed to develop a West Group Area specific floor space model, BPA believes these more sophisticated techniques are needed in order to make the NRDC Scenario more credible.

Issue: NRDC assumes that commercial buildings will be 100 percent retrofitted with conservation measures by 1995 (p. 64).

Response: We believe that NRDC's assumption of 100 percent retrofit of existing buildings by 1995 to the savings levels assumed in the Scenario is unrealistic. Even under the "mandatory" alternative proposed by SOM, compliance was, at least in some cases, assumed to be no more than 80 percent. BPA believes that even SOM's figures may be too high.

Issue: The NRDC scenario, based on the SOM study, assumes that 82.9% of the energy used in large office buildings can be saved (p. 65).

Response: This is an unrealistically high estimate of conservation potential. Most of the conservation measures assumed for the commercial sector are designed to reduce the HVAC load. There are two non-HVAC related conservation actions listed: (1) reducing lighting levels and (2) reducing hot water temperatures. BPA estimates lighting and water heating together to comprise 35 percent of a typical building's electric load (28 and 7 percent respectively). Savings of 30 percent for each of these end uses would result in 11 percent savings of a building's total electrical requirements. Thus energy savings attributable to HVAC conservation would be 82.9 - 11 or 71.9%. The Energy Auditor Manual for the State of Oregon (1980 version) estimates HVAC energy consumption in office buildings to comprise 76% of the total load. Thus the NRDC study in effect states that 94.6% (71.9/76) of the energy used in HVAC equipment can be conserved. In BPA's "most likely" case in its conservation assessment, a savings of 53% in heating energy and 26% in cooling energy is assumed for new office buildings. These values are based on preliminary estimates provided to BPA by the Oak Ridge National Laboratory.

Issue: NRDC uses an assumption of 5145 Heating Degree Days in its commercial sector analysis (pp. 69, B6).

Response: BPA, in its conservation assessment project, has estimated that the West Group Area heating degree days' average is 5773 based on historic data weighted by county. Use by NRDC of a lower heating degree days assumption reduces the amount of energy needed to heat buildings.

MANUFACTURING SECTOR

Issue: In preparing a before-conservation baseline projection for the industrial sector, NRDC increased electricity consumption as a result of the assumption that energy would substitute for labor at a linear (noncompounding) rate of one percent per year (p. 79).

Response: NRDC's assumption about the rate at which energy will substitute for labor appears to be arbitrary. NRDC implies this rate is based on a historical trend, but provides no citation which might support the given assumption. We have looked at fuel usage and employment data contained in the Commerce Department's Annual Survey of Manufactures for the years 1971 to 1976 in an attempt to document this trend. For all purchased energy, we were not able to find any trend in energy-labor ratios over this period for the three Northwest States. Restricting the analysis to electric energy, however, it does appear that the ratio has been increasing.

If NRDC is basing the assumption on a historical trend, there is no guarantee such a trend will continue in the future. The future course of energy-labor ratios will depend on a number of factors, including the technical ease with which factors of production can be substituted for each other, own- and cross-price elasticities, and, of course, the prices of energy, labor, capital, and material inputs over the forecast period. If electricity prices were to increase faster than wage costs (as some forecasters have predicted), it might be reasonable to predict that energy-labor ratios would increase more slowly than a historical trend would suggest. If so, the NRDC assumption about energy-labor ratio trends would result in an overestimate of energy usage.

Issue: From an independently projected baseline of manufacturing total energy consumption, NRDC utilizes a study done for California to subtract a percentage atributable to total energy conservation in the manufacturing sector (pp. 80, C3).

Response: Clearly, it is no easy task to project potential electric energy savings in the industrial sector. NRDC has selected the California study (Benenson, et. al., 1978) and attempted to apply generalized savings factors to BPA's West Group Area. This approach is untenable for several reasons, not the least of which is the lack of the availability of the unpublished source document for Table 3 of the Benenson report from which the California savings factors were generated. There simply is no readily available means to verify the data. Beyond this, several questions should be raised concerning NRDC assumptions in applying the data to the West Group Area.

(1) The savings factors in the Benenson report appear to be based on the assumption of a "four-fold increase in fuel prices" (p. 88). The NRDC Scenario does not include a projection of future fuel prices, but given the claim that electricity prices under the Alternative Scenario will be

lower than under the "Central Station Scenario," it is unlikey that prices will go up that much. With lower price increases, savings factors can be expected to be lower as well.

(2) The nine most prominent industries selected in California differ quite markedly from those in the West Group Area. "Other" industries, considered to be small in California, include Primary Metals and Lumber which account for 59 percent of West Group Area industry's electric energy consumption. Since the same savings factors are applied for all industries in this "Other" category (except for aluminum), the data is unacceptable for adaptation to the West Group Area. Potential savings in the lumber industry (SIC 24) cannot be considered similar to Electrical Machinery (SIC 36). The assumption is far too arbitrary.

(3) Even for 2-digit SIC industries which are specifically compared, the 3- and 4-digit subindustry mix can vary so significantly that a 2-digit SIC comparison is not meaningful. SIC 281 Industrial Inorganic Chemicals, for example, amounts to only 42.6 percent of SIC 28 in California versus 81.2 percent in the West Group Area. Energy intensity varies greatly at the 3-digit level as the ratios in the following table illustrates.

ELECTRIC ENERGY INTENSITY FOR U.S. SIC 28 CHEMICALS
BY 3-DIGIT SIC USING 1975 DATA

	SIC	Consumption in 10^6kWh	Employment (000)	RATIO: 10^6kWh/ EMPL (000)	V.A. ($MIL)	RATIO: 10^6kWh/ $MIL
Chemicals 28		127,693	841.8	151.7	44,976.3	2.84
	281	72,018	109.1	660.1	5,212.9	13.82
	282	15,178	150.2	101.1	5,525.1	2.75
	283	3,223	149.7	21.5	8,030.1	.40
	284	2,053	108.2	19.0	7,247.8	.28
	285	958	59.9	16.0	2,126.3	.45
	286	23,309	137.3	169.8	9,511.4	2.45
	287	8,494	52.1	163.0	4,545.5	1.87
	289	2,459	75.3	32.7	2,777.2	.89

Source: U.S. Bureau of the Census, Annual Survey of Manufactures 1975.

(4) There are some new industrial processes which conserve total energy, yet at the same time will increase electricity consumption. Using chemicals again as an example, the chlorine-alkali industry is considering the membrane process as a replacement for the diaphragm cell process. The membrane process only uses a fraction of the steam necessary for the diaphragm operation while consuming 12.2 percent more electric energy (Beck, 1977, p. 72). Yet the dollar savings per ton product for membranes is 9.5 percent (or $12.90 cheaper), principally because total enegy usage is lower. NRDC does not consider such distinctions in their analysis.

(5) The savings factors apply to total energy, not electric energy. The methodology which NRDC uses implicity make the assumption that the conservation potential for total energy is equal to the potential for

saving electrical energy. That assumption has no validity. The nature of fossil fuel energy use is very different from electricity use, and it is believed that the potential is less for electricity conservation (Barnes, 1980).

Issue: The NRDC Scenario assumes that the aluminum industry will be able to achieve a 20 percent savings factor by 1985 and a 40 percent savings factor by 1995 (pp. 80, 92-96).

Response: The aluminum industry in the Pacific Northwest was estimated to consume 9 kWh/lb in 1976 by Ernst & Ernst (1976, p. V-32), although the NRDC estimate of 8.5 kWh/lb in 1975 is probably just as good an estimate.

By 1985, NRDC believes that the Pacific Northwest plants will consume 6.5 kWh/lb, based on the belief that most plants will invest in plant modernizations (particularly the Sumitomo process). This may be a somewhat optimistic estimate, since at least some actual experience with the Sumitomo process revealed that improvements were only made to a level of 6.9 kWh/lb, rather than the NRDC-quoted figure of 6.5 kWh/lb (McAbee, 1975, p. 19). In addition, the process is limited to plants with Soderberg anodes, and in the Pacific Northwest those plants account for only about 42 percent of regional capacity.

By 1995, NRDC assumes consumption will drop to a level of 5.1 kWh/lb, based on the assumption that the new titanium diboride process now under development will be adopted by all plants, and that the new Alumax plant will use tha Alcoa chloride process. These assumptions are very optimistic; attempts to use the titanium diboride process have been hampered by the relatively short life of the cathodes in an operating cell environment, (Payne and Dorward, 1979, p. ii), and another study has estimated that the TiB_2 process will only reduce consumption to a level of 5.6 to 6.1 kWh/lb (Beck, 1977, p. 67).

One important issue that must be considered is the question of whether any investments in energy-efficient processes will be accompanied by expansions in plant capacity. The Department of Commerce study on the Pacific Northwest aluminum industry has determined that capacity expansions at existing plants can be much less expensive and more profitable that building a new plant (Kristensen and Correia, 1979, p. 82). For example, Martin Marietta has announced plans to expand capacity at its Goldendale, Washington, plant by 65,000 tons/year, an expansion that will require more electricity than is being saved at both Martin Marietta plants through investments in the Sumitomo process. If this pattern continues (as seems likely), the demand placed on central-station generation by the aluminum industry will not decline, even if the efficiency of production improves. Thus it is not prudent to plan for any decline in the aluminum industry load.

Issue: Although NRDC used BPA's employment projections, they expressed "grave doubts" about two assumptions used in the preparation of those projections: the Alumax aluminum plant was expected to be built by 1985, and two new plants in Oregon (Siltec and Wacker) were allocated to the chemicals industry (pp. 81-82).

Response: There is a legitimate question about whether the Alumax plant will be built. Alumax has just completed construction of a 220,000 ton capacity smelter in South Carolina, and given that capacity costs are now probably about $3,000/ton, there may be some doubt about whether Alumax will be interested in or capable of investing a sum in excess of $500 million in a new plant at Umatilla in the time frame assumed in the West Group Forecast. Also, in the absence of any new legislation, Alumax's power sales contract with BPA will be allowed to expire in 1986.

On the other hand, a Department of Commerce study of aluminum demand indicates there will be a potential need for a new U.S. primary aluminum plant by 1986 (Kristensen and Correia, 1979, p. 29). With a valid contract that has a possibility of being extended if pending legislation passes, there is still a distinct possibility that Alumax will be built, and it is only prudent that BPA plan for the contingency of having to serve that load. Energy requirements for Alumax, as included in the West Group Forecast, are 334.5 average MW in 1985 and 369.7 average MW in 1995.

At the time the Oregon population and employment projection was made, the new Wacker and Siltec plants had not been classified into an SIC category, and for bookkeeping purposes they were placed into SIC 28 Chemicals. They now have been officially classified into SIC 36 Electrical Machinery. Using NRDC's methodology, this change would have the effect of reducing the load in the NRDC Scenario by 61.8 average MW in 1985 and 91.8 average MW in 1995 as outlined below:

Load of Siltec and Wacker Plants
Using NRDC Methodology (average MW)

	1985	1995
Classified as Chemicals	63.1	93.9
Classified as Electrical Machinery	1.3	2.1
Difference	61.8	91.8

This provides an interesting example of the sensitivity of the NRDC methodology to very small changes in input assumptions. It also provides an illustration of how the methodology can be inaccurate. The actual load forecast for the two plants, based on information provided by the companies themselves, is a load of about 30 average megawatts in 1985.

Issue: The second phase of the Rocket Research report "concludes that 15 percent more cogeneration output could be obtained from these other cogeneration cycles, yielding a total regional potential of 1,645 MW" (p. 83).

Response: There is some misinterpretation of the information in the Rocket Research report. Other cogeneration technologies, in addition to the steam topping cycle analyzed in Phase I, were evaluated in the Phase III and IV economic analysis. Cogeneration potential in addition to what was originally predicted did result from analysis of these technologies (Rocket Research, 1980, p. 2-2). However, there is also additional condensing cycle generation which was discovered during the detailed analysis of specific industrial sites. The total of the increased cogeneration and generation potential over what was predicted in Phase I was in the order of 15 percent. The 15 percent was then used to extrapolate from the original cogeneration potential predicted to arrive at a total generation potential of 1,645 MW. If the amount of installed, operating capacity is excluded from this extrapolated value of 1,645 MW capacity, the remainder, approximately 1,450 MW, is the technical potential for industrial generation (cogeneration plus condensing cycle generation).

Issue: "Based on these (cost) estimates, we believe that the full 1,645 MW of cogeneration can be developed by 1995. We assumed that slightly less than half of this total will be on line by 1985." (As noted above, more than 420 MW have already been installed.) (p. 84).

Response: We disagree. Factors other than economics are still acting as barriers to cogeneration development. These include limitations in the physical plants' management attitudes in both industries and utilities, fuel supply, financing availability, restrictions in the cost of fossil fuels, integration of an intermittent resource into the utility system, and governmental regulation of industries. Although these factors have not been fully analyzed to determine their impact, some predictions and trends have led us to produce a rough estimate of practical potential. In the initial phase of its study, Rocket reported that some industrial sectors were approaching 75 percent of their technical capacity, but that overall, for most industrial sectors, 50 percent of technical capacity was achievable (Rocket Research, 1979, p. 7-1, 8-1). Upon completion of the economic phase of the analysis, the data showed that at least 50 percent of the plants studied could produce cost competitive electricity by cogeneration (Rocket Research, 1980, p. 4-12). Based on these observations and analyses, we estimate approximately 800 MW capacity as the practical potential for industrial cogeneration and generation. This was derived by assuming the achievement of 50 percent of combined generation potential for new generation opportunities and 75 percent of the cogeneration capacity at plants where most of the equipment is already installed but not operating.

Issue: ". . . the study determined that the average price of this cogenerated electricity would range from 39.4 to 47.6 mills per kWh in 1983 dollars, certainly cost competitive with new thermal generation" (p. 84).

Response: The average price range of the cogeneration projects studied, using 1977 data, is competitive with the new thermal generation cost assumed in the study to be in the range of 35 to 45 mills/kWh (Rocket

Research, 1980, p. 2-11). It must be noted that inflation has significantly increased the bus-bar energy costs for all projects. However, for the individual plants studied under all the financing and ownership options, discussed in the Rocket report, about 50 percent fell within or below the 35 to 45 mill/kWh range (ibid., p. 4-12). Therefore, the remaining 50 percent of cogeneration plants would not be cost competitive when compared to the 1977 bus-bar energy costs using escalation rates of 6 to 7 percent to attain the 1983 cost figures.

Issue: NRDC has not assigned any potential energy savings to the possibility of using waste heat (p. 88).

Response: This is a potentially important source of savings. For instance, steam-electric generation supplies a small part of Pacific Northwest energy, but from our point of view it represents a good potential area on which to work. First, energy loss is high: about two-thirds of the energy produced is lost in the stack or in the cooling tower.

Second, technology exists whereby waste heat can be utilized. Futhermore, energy retrieval techniques developed for the steam-generation plant may well be applicable to other industrial situations. (Our Prototype Energy Retrieval and Solar (PERS) System at Ross Substation has already spurred further commercial development of the system by Carrier Corporation.)

The waste heat from the steam-electric cycle of thermal generation facilities presents an opportunity for productive research on waste heat utilization. According to TVA's estimate in its Watts Bar Waste Heat Energy Park, there is a potential for utilizing 10 percent of TVA's waste heat. Applying that 10 percent potential recovery only to the WPPSS plants, then out of the 2200 MW/hr of rejected heat in generating 1100 MW/hr supply there is a possible savings of 220 MW/hr from each nuclear plant. If realized, these savings could mean increasing the output of the current five plants by one whole plant, through energy utilization.

Issue: NRDC does not believe that fuel availability or cost will be barriers to developing the full technical cogeneration potential (pp. 97, 99).

Response: We disagree. As previously noted under the discussion on costs, only 50 percent of the plants studied were cost competitive. Major factors influencing economics that will still remain as barriers are financing availability, fuel cost, plant ownership, purchase and sale rates of electricity, and pollution control costs (Rocket Research, 1980, Executive Summary). The current low price of electricity also acts as a deterrent to convincing management of the cost competitiveness of their resource in later years.

Also, fuel availability is a critical issue (Rocket Research, 1980, p. 1-7). Magnitude and cost of biomass available for supply has not been adequately assessed. It is also difficult to obtain long-term fuel supply contracts to be able to secure plant financing. Efforts are being made to solve both of these problems, but no quick, easy solutions are available.

A report to the Pacific Northwest Bioconversion Policy Group (March 19, 1980) addresses these issues. This report identifies areas of study, including competition for wood residues, contracting/harvesting policies which deter forest residue utilization, and the economic and environmental considerations in collecting, transporting, storing, processing, and burning forest residue.

Some projects which have been shown feasible by preliminary studies are now on hold due to both the financial outlook and fuel supply considerations. Examples of these are the proposed Lewis County and the Kinzua cogeneration facilities.

Issue: NRDC notes that the cogeneration potential predicted is based only on existing industrial sites. They suggest that additional potential may be found in future sites (p. 98).

Response: We agree. The Oregon Alternate Energy Development Commission predicts 115 average MW for future industrial cogeneration (1980, p. 9). Further work needs to be done for the entire region.

AGRICULTURAL SECTOR

Issue: NRDC assumes reductions in irrigation power demands of 1 percent in 1985 and 10 percent in 1995 due to efficiency improvements, solar and wind energy use, and diversion to hydrogeneration (p. 104).

Response: These estimates of conservation potential may be low. The Northwest Agricultural Development Project (NADP) study (Cone, 1979, p. VII-4) estimated an irrigation electric conservation potential in the Northwest of 1.4 percent due to irrigation scheduling, 9.4 percent due to low pressure irrigation systems, and 12.5 percent due to improved pumping plant efficiency by the year 2000. These estimates do not include wind and solar potential. The NADP estimated potential is based on regional economic efficiency--not on technical or economic feasibility, so it should be considered preliminary.

Issue: NRDC lists its projections of central station electrical energy requirements for agriculture in Table 26 and states that 1995 consumption exceeds 1975 by 45 percent (p. 105).

Response: There are several problems with the irrigation load projections. First, using the 1975 base of 3.51×10^9 kWh from Table 26 and the estimated growth rates from Table 25, it was not possible to duplicate the 1985 and 1995 projections so it is impossible to evaluate their validity. A recent (tentative) BPA effort at projecting West Group Area irrigation loads estimated 5.1 MkWh per year for 1985 (compared with NRDC's estimate of 4.6 MkWh) and 6.3 MkWh for 1995 (NRDC - 5.7 MkWh). The 45 percent growth in load between 1975 and 1995 on Table 26 appears to be in error.

Issue: NRDC states that electricity consumption in irrigation may be lower than their estimates because of the loss of hydrogeneration caused by irrigation diversions (p. 108).

Response: Irrigation diversions do indeed reduce hydrogeneration, but this does not restrict irrigation development. The decision to irrigate is a private sector decision made by irrigators without regard for generation losses. It is unlikely that institutional changes will be made that will alter that fact (Foleen, 1979).

ALTERNATIVE ENERGY SUPPLY POTENTIAL

Issue: NRDC states that wind energy generation has "virtually no detrimental effects on the environment" (pp. 112-113).

Response: This may be true relative to other sources of generation. However, serious television interference and noise problems have been experienced at all wind sites to date (University of Michigan, 1978; BPA, December 1979) and aesthetic considerations may limit its implementation at certain sites.

Issue: NRDC states that the Pacific Northwest has a large wind energy potential (p. 113).

Response: We agree. Studies conducted subsequent to the NEPP study support a significant wind potential in the Pacific Northwest (BPA, June 1980).

Issue: "The task force also predicted that, by 1985, large wind machines would be generating 130 MW of power" (p. 114).

Response: The wind task force final report to the Alternate Energy Commission (June 1980, p. 13, Table 2-4), indicates that 10 MW capacity could be installed in Oregon by 1985, not the 130 MW reported in the NRDC document.

Issue: "At times of low demand, wind machines can pump water uphill, to be impounded and released later when the winds have dissipated" (p. 114).

Response: Only one pumped storage facility now exists in the Pacific Northwest. Construction of pumped storage facilities dedicated to wind energy would significantly increase the net cost of wind energy operation. Studies are required which examine the potential benefits of developing pumped hydro in conjunction with wind in the Northwest.

Issue: "The diversity of wind patterns throughout the entire Northwest would ensure that some generation is always occurring" (p. 114).

Response: Preliminary studies indicate that the amount of capacity credit that could be allocated to a wind network spread throughout the Northwest is under 10 percent (BPA, June 23, 1980).

Issue: "In addition, the region has a ready made storage device in its hydro electric system" (p. 114).

Response: Although the region's hydroelectric system does offer a ready made storage medium for wind energy, preliminary studies indicate that from 16 to 37 percent of the energy produced by a hypothetical wind network would not be usable due to operation constraints (BPA, June 23, 1980).

Issue: The Scenario cites a study that states that vertical-axis wind machines will generate electricity at between 2 to 4 cents per kilowatthour (p. 114).

Response: The economic viability of the vertical-axis wind machine has not been demonstrated. It is also important to tie all cost estimates to a common date so that they can be properly compared.

Issue: "We do not assume a contribution from geothermal and biomass sources beyond those already discussed in the end use analysis" (p. 116).

Response: We agree. Although many wood burning plants have been proposed, to date there are no commitments for construction of such facilities.

Until the binary cycle pilot project at Raft River proves successful, the Pacific Northwest cannot plan to utilize the geothermal resource for electrical generation.

Issue: The scenario assumes 75 MW of wind capacity will be developed by 1985 and 1,000 MW by 1995 (p. 116).

Response: Achievement of these levels of wind development in these time frames assumes that no serious problems are encountered with prototypes currently scheduled for installation in the Northwest and California. In addition, 75 MW of wind capacity by 1985 assumes that the Northwest receives a large share of the national production of wind turbines.

Issue: The scenario predicts the expanded use of many alternative resources, including fuel cells, photovoltaics, wind machines, biomass conversion, municipal waste recovery, and on site wind waste burning for electrical generation for 1995 and beyond (pp. 117, 118).

Response: We agree. Although our emphasis is on near-term development, the literature seems to support these choices for future development beyond 1995.

IMPLEMENTATION

Issue: The Scenario contemplates a massive conservation effort, with significant mandatory features, to weatherize Northwest residences. The measures contemplated are based on Strategy 6 in the SOM study (p. 203).

Response: With only a few exceptions, Federal/State/local entities have been quite reluctant to adopt mandatory programs in the weatherization area. Although Seattle and Portland have made some initial tentative steps in this direction, both cities now are backing off from earlier plans in face of considerable local opposition. Seattle's program, for example, has been revised so its mandatory elements will not take effect until 7 years after initial weatherization efforts begin. The U.S. Congress and State legislatures, in turn, have repeatedly opted for various incentive/regulatory programs in this area, rather than adopting the mandatory approach. In short, NRDC's residential weatherization strategy depends on implementing programs for which BPA or other Federal/State/local bodies currently have no legislative authorization, and which will be quite controversial in whatever legislative body is asked to approve them.

NRDC candidly suggests that mandatory measures are the only effective way to retrofit existing structures (p. 203). They correctly observe that "expense and inconvenience are inevitable" regardless of which course the region takes (to fulfill its energy needs). Although NRDC recommends three principles for minimizing the burdens of mandatory programs, they fail to calculate the effect of political resistance to such measures on the rate at which those measures can be implemented. Their logic links an arguably valid conclusion--that extensive mandatory measures are necessary--to a second conclusion which ignores the consequences of their first premise--that such contentious measures can be implemented quite rapidly throughout the Northwest (i.e., covering 90 percent of Northwest residents by 1995).

Further NRDC discussion and comparison of State/local building codes (pp. 190-191) is also illustrative. It demonstrates that: (1) not all States and only a few local governments have adopted any form of energy efficient building codes; and, (2) those codes already adopted or proposed still fall well short of Scenario insulation levels. This experience tends to confirm that legislative action on weatherization will come slowly, and that it will get increasingly harder to obtain as codes become more stringent. Again, experience to date is not encouraging that mandatory measures can be implemented and achieve significant savings by 1995.

Issue: The Scenario contains a section entitled "Reform of Bonneville's Rate Structure." In this section and other sections discussing utilities' pricing policies, NRDC claims that electric utilities generally and Bonneville specifically should implement marginal cost pricing. NRDC contends that Bonneville's current practice of developing average cost based rates conceals the cost of new thermal generation. Furthermore, at the very least, Bonneville should establish a two-tier rate structure that differentiates between the low cost of existing hydroelectric supply and the high cost of new thermal generation. That is, hydroelectric energy should be allocated among Bonneville's preference customers at a low rate and any power consumed above this allocation should be charged at the high cost of new thermal.

Response: NRDC contends that Bonneville's present pricing policies are inefficient and cause over-investment in new supply sources and under-investment in conservation measures. Furthermore, NRDC argues that Bonneville should base its power rates not on average cost but rather on the cost of new thermal resources, the long-run incremental cost (LRIC) of energy.

At the present time there exists a nationwide controversy in the electric utility industry concerning the use of LRIC-based rates for electric power. Many of the arguments presented by NRDC have been presented before with regard to LRIC pricing. Bonneville staff has followed this controversy over the last five years and has evaluated, as have other utilities, the advantages and disadvantages of this pricing approach. Some state public utility commissions, such as Oregon's, base the allocation of costs to customer classes on the results of an LRIC study with revenues adjusted to a utility's revenue requirement, while others use only an embedded average cost approach.

President Carter signed the Public Utility Regulatory Policies Act (PURPA) into law on November 9, 1978. PURPA is one of five parts of the National Energy Act intended to address the country's energy problem. Title I of PURPA entitled "Retail Regulatory Policies for Electric Utilities," deals primarily with electric utility rate reforms and in many cases requires a consideration of marginal cost pricing. Bonneville, as an electric utility covered by Title I, was required to hold a hearing on various ratemaking standards and to make a determination concerning their applicability to Bonneville's electric power rate structures. The Administrator's Determination Order adopting the standards stated in part that: "In prescribing such methods (used to determine the costs of providing electric service to each class of electric consumers) Bonneville will use embedded and long-run incremental costs." Section 131 of PURPA gives the Secretary of Energy the authority to prescribe voluntary guidelines when considering the standards. Generally, the voluntary guidelines encourage utilities to adopt marginal cost pricing whenever possible. Moreover, under Section 133 of PURPA Bonneville is required to submit an LRIC study to the Federal Energy Regulatory Commission (FERC).

As part of the 1979 wholesale power rate filing, Bonneville developed a Long-Run Incremental Cost of Service and Rate Study for the Federal Columbia River Power System (FCRPS). The results of the LRIC study were used as a guide to rate design throughout the rate development process. Rate adjustments based on LRIC pricing were used to give price signals to our customers as to the direction of future capacity and energy costs. Consequently, preparation of an LRIC study and the use of the results of that study in rate design have been a part of the Bonneville rate development process.

The LRIC approach is a practical application of the economic theory of marginal cost pricing to electric rates, given the constraints under which utilities operate. The LRIC is the cost of producing additional electricity, taking into account the need to add more plant units. The theory indicates that, if the prices of all commodities are set equal to their marginal costs, available resources will be allocated to society's maximum satisfaction. The theory's underlying assumptions are complex, but the reasoning is straightforward. At any point in time, the economy has a fixed amount of productive resources. The basic economic problem is to make the most efficient use of these finite resources. It follows that the cost to society of producing anything consists of the goods and services that must be forgone for the chosen production. Consequently, if the region's consumers are to decide intelligently whether to buy somewhat more or less of any item or service, the price they pay for all units of the item must reflect the cost of supplying somewhat more or less, or the marginal cost.

If consumers are charged more than marginal cost for a good or service, they will buy less than the optimum amount because the price exaggerates their sacrifice of other units of goods and services. Conversely, if the price is below marginal cost, perhaps because the additional production is subsidized, the output would be higher than the optimum amount. Moreover, society would be sacrificing more of other units of goods and services to produce larger quantities of the subsidized product than customers would willingly have purchased, had the price for the item fully reflected the marginal or extra cost associated with producing more output. The purpose of a price based on marginal cost is to convey to consumers of a good or service a price signal reflecting the cost to the producer which would be incurred if additional units are produced.

There is little disagreement that given the conditions that the theory describes, for example, that all other goods and services in the economy are priced at LRIC, an efficient allocation of resources would result. In most discussions of LRIC pricing the theory is not at question. The controversial questions arise when LRIC pricing is applied in a social and institutional environment where the theoretical conditions may not exist. Since the equality of price and marginal costs leads to optimal welfare and efficiency only if it applies to all other goods and services, many argue that marginal cost prices should not be implemented by utilities because many other products are not priced at marginal cost. Further, it is argued that basing electricity prices on marginal costs would have a severe effect on the region's social and economic welfare.

It is generally accepted that pricing as many goods as possible at marginal cost would not necessarily provide a "second-best" solution. In fact, the opposite may be true, particularly in situations where close substitutes are priced above or below marginal costs. However, this problem cannot be used to invalidate the use of marginal cost pricing in all cases. Any utility considering marginal cost pricing must make a thorough analysis of the effects of such a pricing scheme on the market in question and the effect on other close substitutes or complementary products. The close substitutes for electricity in the Pacific Northwest, oil and natural gas, are priced near their marginal cost. Consequently, implementing LRIC pricing for electricity in the Pacific Northwest does not appear to be affected by this theoretical problem.

Bonneville has analyzed the effects of instituting LRIC-based rates in the Final Environmental Impact Statement for the 1979 wholesale rate increase. The analysis indicated that the long-run load growth under LRIC-based rates is substantially less than under Bonneville's present pricing policy and consequently, fewer new generating units would be required. Bonneville's analysis also showed that a direct shift from average cost pricing to LRIC pricing would cause considerable short-run economic and social dislocation for the Pacific Northwest Region. Because Bonneville's marginal cost of electricity is very high in relation to its average cost and because the region relies heavily on electricity for space heating, irrigation pumping, and manufacturing processes, a wholesale revenue increase based on marginal costs would have an immediate and dramatic impact on social and economic welfare in the Pacific Northwest. The Pacific Northwest has benefited greatly from the relatively low cost of the FCRPS. However, the region has become very dependent on electricity, more so than any other region. Other regions have traditionally generated electricity from thermal resources which are considerably more expensive to operate than the FCRPS. Consequently, if utilities that rely on thermal generation adopted LRIC pricing, less drastic effects would result than would be the case if marginal cost pricing were implemented in the Pacific Northwest.

Nevertheless, because Bonneville's average costs are increasing rapidly due to the relatively higher costs of new generation and transmission resources, Bonneville's wholesale power rates have reflected the rising cost of developing these new resources. Price signals reflecting the cost of new resources are being sent to Bonneville's customers in the form of an 88 percent revenue increase which went into effect in December 1979, and an estimated 50 percent revenue increase which is expected to go into effect in July 1981. These price signals are informing Bonneville's customers that additional resource costs associated with load growth are very expensive without producing the economic and social dislocations associated with an abrupt revenue increase based on LRIC pricing.

Even if LRIC pricing were appropriate and the significant economic and social dislocation effects could be minimized, Bonneville does not have the legislative authority to base its revenue level on LRIC. Bonneville's current statutory obligation is to set rates at a level sufficient to produce revenue that will meet repayment requirements. The FCRPS revenue requirement is determined through preparation of a repayment study which calculates the minimum amount of revenue required to recover all FCRPS costs including purchase power, operation and maintenance expense, interest, and amortization of the investment in power facilities within the prescribed repayment periods. In addition, power revenues must repay that portion of the construction costs of Federal irrigation projects which are beyond the ability of the irrigation and water users to pay. The test of sufficiency of revenues is that costs are recovered within the repayment period.

NRDC claims that, if Bonneville is unable to implement LRIC pricing, there exists a "second-best" pricing method that induces more conservation efforts than Bonneville's current pricing policy. This two-tiered rate structure requires basing the revenue level on the repayment requirement but creating rate differentials based on differentials in the cost of generation resources, specifically one rate for hydroelectric resources and one rate for thermal resources.

Bonneville has analyzed the effects of baseline power rates in the Final Environomental Impact Statment for the 1979 wholesale rate increase. One alternative examined was to market a limited amount of power at a rate based on the average cost of generation from Bonneville's hydroelectric facilities with the rate of all remaining power based on a weighted average of the cost of Bonneville's net-billed thermal generation. Under this two-tier hydro/thermal rate, the baseline rate would reflect the average cost of hydroelectric resources. This cost would vary slightly in the future due to increases in operation and maintenance expense and the addition of new hydroelectric units. As additional thermal power is integrated into Bonneville's system, the differential in a baseline hydro/thermal rate would increase. The analysis indicated that by the year 2000, the impact of the baseline rate on second-tier customers would be substantial with second-tier costs running approximately 2 to 4 times the baseline cost. However, it is the opinion of Bonneville's General Counsel that Bonneville currently lacks authority to implement rates based on cost differences between thermal and hydroelectric generation plants.

Nevertheless, Bonneville is examining alternative rate structures which would include incentives and price signals encouraging its customers to adopt conservation oriented rate structures. One problem to be overcome in implementing a conservation rate is insuring that the economic impact of the wholesale rate is reflected in retail rates. Through Bonneville's current retail rate review process, Bonneville encourages those customers retaining declining block rates to implement an alternative rate structure with a flat energy charge which encourages conservation at all consumption levels. In addition, Bonneville is presently examining various alternative wholesale rate designs that would encourage conservation on the part of its direct service industrial customers.

LEGAL RESPONSE TO NRDC'S SUGGESTIONS FOR BPA ACTION

The NRDC Alternative Scenario contains specific suggestions for action by BPA to further the region's progress towards full exploitation of conservation and renewable resources. These suggestions involve the areas of wholesale rate design, the use of allocation policy and contracting authority to force customer involvement in effective conservation efforts, and the provision of technical and financial assistance for customer conservation programs and consumer retrofits and renewables purchases. For the most part, policy differences between these suggestions and the positions taken by BPA are minimal. BPA has already implemented many of the suggestions advanced by NRDC but on a smaller and, in the case of ratemaking, less direct scale. Long-run-incremental-cost pricing was used as a guide to the design of the rates filed in the 1979 power rate filing. BPA is currently developing an allocation policy which will condition access to some of the available energy on a customer's conservation performance. Weatherization, solar, wind, and pump-testing pilot programs make financial and technical assistance and training available. A regional end-use survey has been conducted. The major differences which exist between NRDC and BPA involve the issue of BPA's current legal authority to implement the Scenario's suggestions on the scale suggested. However, legislation now pending in Congress could provide the authority to implement most of them to the extent suggested.

<u>Issue</u>: Does BPA have the authority to implement unconstrained marginal cost pricing?

<u>Response</u>: The NRDC suggests that BPA give far more serious consideration than it has in the past to marginal cost pricing in setting its power rates. The NRDC authors, however, seem to acknowledge the legal difficulties involved in implementing this suggestion by referring to the issue as a "charged question." The statutes which control Bonneville's marketing of Federal energy clearly impose a different criterion. The Flood Control Act of 1944, as amended, under which some of the region's hydroelectric projects were authorized, states that surplus power and energy shall be disposed of "in such manner as to encourage the most widespread use thereof at <u>the lowest possible rates</u> to consumers consistent with sound business principles." 16 U.S.C. 825s. (Emphasis added) The Bonneville Project Act's legislative history is replete with references to the goal of marketing cheap electric power so as to ensure the sale of all power that is generated, to serve as a yardstick against which to compare the price of power privately generated and sold, and to aid in the economic development of the Pacific Northwest. The Federal Columbia River Transmission System Act requires that the rates for the sale by the Administrator of <u>all</u> electric power be established "with a view to encouraging the widest possible diversified use of electric power at the <u>lowest possible rates</u> to consumers consistent with sound business principles." 16 U.S.C. 838g (emphasis added). Both the Bonneville Project Act and the Federal Columbia River Transmission System Act require power rates to be set at levels sufficient to recover the cost of producing and transmitting the power, including the amortization of the capital investment in the facilities.

Issue: Does BPA have the authority to impose a two-tiered rate structure which contains separate hydro and thermal rates based on the average cost of each type of energy source?

Response: In lieu of imposing unconstrained marginal cost pricing on all BPA power and energy, the NRDC suggests that BPA should establish a rate structure that differentiates between hydro generation and thermal generation, i.e., a two-tiered rate structure. This two-tiered rate structure would average the cost of all hydro generation as the basis for a hydro rate, and would also average the cost of all thermal generation as the basis for a separate thermal rate. The concept of averaging costs for ratemaking purposes, often referred to as "melding" of costs, has a long history in the utility business as well as in the operations of Federal power marketing agencies. Bonneville has melded its hydro costs since 1941 with the express approval of the Federal Power Commission and the implicit approval of Congress which was made evident in the authorizations for additional Northwest hydro projects. This melding of hydro costs was officially approved and thereafter mandated by the Congress in legislation authorizing the third power plant at Grand Coulee Dam (Public Law 89-448). Bonneville's inclusion of thermal costs in this melding approach was explained to the Congress prior to its concurrence in the Hydro-Thermal Power Program's net-billing agreements.

The General Counsel has determined that the rate setting sections of the Bonneville Project Act and the Federal Columbia River Transmission System Act require the melding of Bonneville's hydro and thermal costs. In an opinion issued March 12, 1979, he stated:

> The only manner in which the thermal power (of the hydrothermal power program) could be integrated into Bonneville's system and at the same time encourage 'the widest possible diversified use of electric energy' as required by Section 6 of the Bonneville Project Act and at the time same time 'in such manner as to encourage the most widespread use thereof at the lowest possible rates' as required by 16 U.S.C. Section 825-5 would be to meld such rates into the lower hydro rates, a practice which BPA had followed for more than 25 years before the hydrothermal power program was implemented.
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> . . .
>
> The Bonneville Project Act, which requires that rates set by Bonneville be set 'with a view to encouraging the widest possible diversified use of electric energy' and the Transmission System Act which requires that 'rates shall be fixed and established with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles' would require that rates of an integrated system such as Bonneville's should meld the costs associated with the individual projects which make up the system."

In addition, Bonneville has explicitly stated to the Congress, and Congress has recognized in Committee Reports, that it would meld the costs of thermal power with the costs of hydro power to produce a power rate which would soften the impact of thermal costs on the region. Bonneville clearly stated this intent in a preliminary report on the Ten-Year Hydro-Thermal Power Program dated October 9, 1968, in which it stated: "This acquired power will be melded with the Federal hydro system, and the integrated product will be sold to BPA's customers at uniform rates." In hearings before the Public Works Subcommittee of the House Appropriations Committee, Bonneville Administrator Richmond provided a lengthy statement to the Committee which included the statement that:

> Thermal power thus acquired would then be integrated with Federal hydro and sold to BPA customers at BPA rates. (House Subcommittee on Public Works, 91st Cong., 2nd Sess., Public Works for Water, Pollution Control, Power Development, and Atomic Energy Commission Appropriation Bill, 1971 (1970), at 828. See also the statements at pp. 830, 865, and 866-867.)

Bonneville believes that it must at least return to the congressional appropriations committees to seek approval of a two-tiered hydro and thermal rate structure if it decides that such a policy is warranted. A major reason for Bonneville's request for congressional approval of the Hydro-Thermal Power Program was to assure bond counsel, who would have to certify the bonds issued by publicly-owned utilities, that the output of the planned thermal plants would have an assured market. Part of this assurance was a sufficiently low rate for this thermal power to insure ready marketability and therefore continued revenues for BPA which would be used to pay for the power purchased under the net-billing contracts. It would therefore be at least a breach of faith not only with bond counsel and their utility clients but also with Congress for Bonneville to restructure its rate design contrary to the assurances previously given. With the near certainty of litigation in the event of such a major policy change, Bonneville's General Counsel could not commend or authorize such a change without Bonneville returning to the Congress to seek explicit authorization for such change.

Issue: Does BPA have the authority to require strict conservation programs, including conservation-oriented rates, as a prerequisite to access to Federal power in the allocation program and in new power sales contracts?

Response: NRDC suggests an allocation program which apportions the available energy in a different manner than that suggested by Bonneville's program, imposes specific and strict prerequisites for distribution of the conservation reserve, and involves Bonneville in extensive customer-specific end-use analysis. The cornerstone of the suggested policy is that "no preference customer is automatically entitled to more inexpensive BPA energy than it can use efficiently." NRDC's suggested program requires Bonneville to survey the electrical energy end uses in the residential, commercial, agricultural, and industrial sectors in each customer service area and to project likely additions to those inventories. Bonneville would also be required to estimate the amount of electricity that the various structures and processes in the inventory would require if they were functioning efficiently. Preference customers would receive a base allocation of Federal energy which would correspond to the latter amount of electricity. The energy in excess of the total base allocations would form a conservation reserve which would be divided in portions proportionate in size to the individual base allocations. Access to these shares of the conservation reserve would depend upon utility adoption and effective implementation of conservation programs and policies prescribed by Bonneville. Examples of the latter would include strict heat loss standards, as well as lighting and electric motor efficiency standards, for new construction and conversion; energy audits of existing commercial and industrial customers; NECPA-type conservation measures for residential conservation; and financing for residential conservation measures.

Bonneville has the legal authority to establish a pool of withheld energy and conservation-based criteria for allocation of that energy. Based on the analysis provided by the 9th Circuit Court of Appeals in City of Santa Clara v. Andrus, Bonneville has the freedom to determine the criteria for the distribution among its preference entities of the energy it markets. The NRDC's suggested allocation program, with the exception of one suggested prerequisite discussed below, appears to comply with statutory directives related to the management and distribution of Federal energy. The authority of Bonneville's preference customers to implement all of these suggested prerequisites for access to the conservation reserve is, however, somewhat doubtful in light of the various prohibitions and mandates contained in the laws of the various Northwest states. Bonneville's authority to engage in extensive energy end-use analysis would have its source in Section 2(f) of the Bonneville Project Act and Section 11(b)(4) of the Federal Columbia River Transmission System Act.

The one legally doubtful prerequisite suggested by NRDC for access to the conservation reserve and, in new power sales contracts, to any Federal energy is that related to establishing conservation-oriented retail rates. Thus, NRDC suggests that BPA prohibit the use of declining block rates by its customers and require its customers to establish inverted rates under the authority of Section 5(a) of the Bonneville Project Act:

> Contracts entered into with any utility engaged in the sale of electrical 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 ensure that resale by such utility to the ultimate consumer shall be at rates which are reasonable and nondiscriminatory.

NRDC refers to a number of Department of Interior Solicitor Opinions and Comptroller General Opinions which it believes support its claim that Bonneville possesses the authority to require conservation-oriented rates. The General Counsel cannot agree. These opinions discuss authority granted by Section 2(f) Bonneville Project Act:

> Subject only to the provisions of this Act, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof and the compromise or final settlement of any claim arising thereunder, and to make such expenditures upon such terms and conditions and in such manner as he may deem necessary.

Though the authority provided by this section is, as NRDC claims, "wide-ranging", it is limited by other sections of the Act. Read in pari materia with other legislation controlling Bonneville's marketing of Federal power, as is required by an Attorney General Opinion (41 Op. Atty. Gen. 236 (1955)) which is referred to in a leading opinion cited by NRDC, the Bonneville Project Act requires the establishment of the lowest possible rates for the sale of Federal power. Such rates were to ensure the sale of all power that is generated, to serve as a yardstick against which to compare the price of power privately generated and sold, and to aid in the economic development of the Pacific Northwest. Given such a mandate, it would be ironic at best to conclude that Section 2(f) authorizes the Administrator to require Bonneville's customers to charge rates which are higher than necessary to produce sufficient revenues to cover the customers' operating costs. It is also important to note that Section 2(f) arguably does not apply to retail rate authority at all, since Section 5(a) specifically focuses on this authority.

Section 5(a) is similarly restricted to "the purposes of this Act." The legislative history of the Bonneville Project Act supports the contention that this particular portion of the Act was included to provide Bonneville with the tools to prevent its customers from charging unnecessarily high rates for inexpensive Federal power and thereby frustrating the "widespread use" and "domestic and rural" orientation of the Act. Similar provision with a similar history can be seen in the Tennessee Valley Authority legislation at 16 U.S.C 831i (1976), though that legislation specifically authorizes the TVA to establish rate schedules for its customers whereas the Bonneville Project Act refers only to terms, conditions, and stipulations related to resale rates which may be inserted into contracts.

It is problematical whether the "purposes of this Act" can be construed to include the end-use conservation of Federal energy in a time of shortage in order to make more of the energy available to new applicants and to existing customers with growing demand, or to avoid the high costs of purchasing additional supplies to meet projected shortages in the supply necessary to fulfill contractual obligations. Assuming such a construction can be found to be within the discretion of the Administrator or to be a reasonable interpretation of the language of the Act, its implementation is affected by two policy matters and one legal requirement.

First, the Bonneville Project Act was built upon faith in the ability of citizens to control their own living conditions, given the institutional tools required. Requiring specific rate structures runs contrary to this deference to democratic decisionmaking. Bonneville has, except for very rare exceptions, always resorted to persuasion when it had significant disagreements over rate matters with its preference customers.

Second, independence in rate making is a subject of high importance to preference entities in the Northwest. In an area of questionable legality such as Bonneville's authority to require conservation-oriented rate designs, it is prudent for Bonneville to first seek other effective methods of inducing conservation prior to embarking on a course which is almost certain to produce litigation.

Third, even if Bonneville could require conservation-oriented rates, its authority is constrained by the overall revenue limitation, i.e., the rate design as a whole cannot produce revenues which are greater than reasonably necessary to operate the utility on sound business principles.

The Administrator may, however, take into account the existence of conservation-oriented rate designs, or the lack thereof, in his choice of which preference applicants he will sell energy to, under the discretion upheld by the Ninth Circuit Court of Appeals in City of Santa Clara v. Andrus.

Issue: Does BPA have the authority to provide conservation financing and technical assistance to its customers, regional consumers, and others?

Response: As part of its alternative energy scenario, NRDC envisions Bonneville providing loans or cash credits to its preference customers in order to finance the initial costs of utility conservation programs and, where necessary, to ultimate consumers to finance conservation and renewable resource improvements. It is assumed that these loans would be at no interest or at an interest rate below that established for normal Federal loans. The General Counsel has previously addressed himself to the issue of Bonneville's authority to engage in such conservation efforts. In an opinion dated March 2, 1979, and entitled "Need for Express Congressional Approval Authorizing BPA to Implement Long-Range Conservation Programs," he stated:

> The power marketing statutes pursuant to which the Bonneville Power Administration conducts business contain no express authority to acquire the long-term output of any project, nuclear, conservation, or otherwise. While implied authority is

> found, it is limited to the purchase of energy that can demonstrably be shown to maximize the economical and efficient operation of the hydro projects from which BPA markets power. The use of such authority to engage in conservation is therefore limited; conservation can be engaged in not for its own sake, but only to the extent that it can be shown to augment the hydro resource or to meet temporary deficiencies in the Administrator's contractual obligation to deliver power . . . The participation of BPA in an extensive conservation program which is not directly related to and subservient to its power marketing and transmitting responsibilities would require express Congressional approval . . . .

See also the General Counsel Opinion dated August 1, 1979, entitled "Authority to Engage in Energy Conservation Programs" and the U.S. Department of Justice Opinion dated October 12, 1979, entitled "Authority of Bonneville Power Adminstration to Conduct Pilot Conservation Programs." Thus, Bonneville does not presently have the authority to engage in a full-fledged commitment of its resources to the conservation efforts envisioned by NRDC. Bonneville does have the authority, however, to engage in such efforts on a research and development basis and as a short-term purchase of energy to meet temporary deficiencies in electric power which the Administrator is obligated by contract to supply. This authority is implied in the Bonneville Project Act and is expressly stated in Section 11 of the Federal Columbia River Transmission System Act. The program envisioned by NRDC cannot be described either as research and development or as a short-term power purchase. Bonneville has utilized its power purchase and research and development authority to establish pilot conservation programs similar in character to those suggested by NRDC with a view toward full-fledged implementation upon the receipt of additional Congressional authorization.

NRDC also states that BPA should provide technical assistance to its utility customers to help them implement conservation programs in their service districts. Examples of such assistance include the training of utility personnel as energy efficiency consultants, i.e., energy auditors, for all end-use sectors; aiding utilities in establishing the administrative machinery necessary to help customers select and finance improvements identified in the audits; and providing computer analysis programs to the auditors to help them in their analysis of lighting design, load calculations, waste-heat utilization, industrial process modification, economic and financial studies, and cost estimation. Additionally, NRDC suggests BPA provide training and computer programming services to architects, building contractors, engineers, and heating and cooling contractors on energy-efficient design, building standards, solar and wind energy systems, and waste heat utilization for commercial and residential buildings. It is also suggested that BPA provide a regional conservation information service which would contain a regional computer data base of all district end-use surveys and data on its own and others' energy research and development projects as well as the results of any regional conservation studies. Finally, NRDC advises BPA to develop a load management research and development program to develop hardware systems and devise strategies for reducing peak hour demand through waterheater and air conditioner cyclers, commercial and industrial demand control systems and devices, and electrochemical, thermal, and mechanical electricity storage systems. This program, it is suggested, should also research potential improvements in the efficiency of utility systems and operating practices.

While there is currently no express authority in Bonneville's controlling legislation to implement most of the above technical assistance programs, previous opinions of the Office of General Counsel have found implied authority for Bonneville to engage in public outreach efforts, alone and in cooperation with its customers, which had as a goal the building of the electrical load of its customers. Such efforts were found to be authorized as methods to carry out the Administrator's duty to market the power from the Federal System and to insure the widespread use of such power. Similarly, the Administrator has the implied authority to carry out the training programs envisioned by NRDC in order to aid the region to use its electric energy more efficiently in a time of shortage. Research related to the efficiencies of customer distribution systems would also be authorized. The suggestion for the establishment of a central repository for all regional end-use surveys would present no legal problems, but NRDC's suggestion for a full scale energy research library primarily for the benefit of the public and BPA customers does present questions of authority which could be resolved through an internal DOE delegation of authority. Finally, research into load management techniques and devices is justified under the electrical reliability research and power marketing expenditure authorities granted by Sections 11(b)(3) and 11(b)(4) of the Federal Columbia River Transmission System Act.

BPA has initiated training of energy efficiency auditors as part of its residential weatherization pilot program and has established in cooperation with participating utilities very favorable financing programs for weatherization. BPA is currently nearing completion of a pilot solar water heater program which will also involve training of utility personnel and will pay a portion of the purchase of the system while financing the remaining cost of purchase and installation. BPA has also trained utility personnel as part of its irrigation pump-testing program. Other examples of BPA's financial and technical assistance in the conservation and renewables field include the funding of Oregon State University studies into suitable wind energy sites and the partial sponsorship of the MOD-2 wind turbine generators being installed at Goodnoe Hills, Washington. BPA will continue to utilize its present authority to initiate new programs related to conservation and renewable resources until additional authority is obtained. NRDC's technical assistance suggestions will receive careful consideration in the development of new programs.

STATE, LOCAL GOVERNMENT, AND UTILITY IMPLEMENTATION
OF NRDC'S ALTERNATIVE SCENARIO

While providing an informative overview of the State, local Government, and utility conservation and renewable resource programs in the Pacific Northwest, the NRDC Alternative Scenario also presents a plethora of suggestions for further action. A brief outline of such suggestions follows:

1. Supply-Oriented Measures

   a. Research and Development. The States should provide research and development funding for alternative generation technologies.

   b. Financial Incentives for Producers. The States should provide tax credits and other incentives for investment in alternative generation technologies and should use their purchasing power to stimulate the growth of alternative sector production capabilities.

   c. Alleviating Utility-Created and Regulatory Obstacles. State utility regulatory commissions and publicly-owned utilities should adopt inverted rates, eliminate declining block rates, and seriously consider replacement cost pricing.

   d. Required Use of Alternative Technologies and Conservation. States should require the utilization of all cost-effective conservation and alternative generation technologies to meet demand prior to granting approval for new central station generation. States should also prepare their own independent projections of electrical demand to balance those of the utilities.

2. Demand-Oriented Programs

   a. Education. Though acknowledging the limited consumer interest in the NECPA-type residential audits, utilities should continue, or immediately implement, such auditing programs. Commercial and industrial facilities should also be audited, and local governments should consider mandatory audits designed to identify retrofit actions, industrial process modifications, and mechanical system efficiencies.

   b. Financial Incentives. The State governments should initiate or expand opportunities for income tax deductions and credits, as well as property tax exemptions for conservation and renewable energy expenditures. States should also initiate or expand programs which reward lenders who make low-interest financing available for conservation and renewable resource development. NRDC suggests either (1) reduced corporate taxes to allow lenders to recover at least part of the difference between the market rate of interest and a reduced rate adopted especially for conservation and renewables loans or (2) state regulatory commission action to allow utility lenders to earn a profit on each loan until repayment is received. Publicly owned utilities would benefit from neither of the above suggestions. NRDC does note that Washington publicly owned utilities, because of a recent constitutional amendment and statutory action, are now able to provide financing for residential conservation and more efficient use of energy. It is doubtful whether this new authorization allows for the financing of anything other than insulation of homes. NRDC emphasizes that both publicly owned and private utility financing programs should include assistance for commercial and industrial enterprises in financing conservation and renewable resource projects.

NRDC suggests a negative incentive be employed where private utilities do not actively invest in conservation and renewables, for example, by adjusting the rate of return to reflect performance in relation to previously established conservation, renewables, and cogeneration targets.

c. End-Use Regulation. NRDC advises significantly stricter building energy codes for new and rehabilitated buildings, requirements for individual electric meters in new apartment units, and requiring solar and wind devices to be considered in all public and private projects where a city or State code requires the use of a registered architect or engineer. Mandatory building retrofits are also advised. The standards for such retrofits should be higher than either those recommended by the City of Portland or by the City of Seattle. Broadly-based financing mechanisms must be a central part of any mandatory retrofit program in order to redistribute first costs of investments "so that as far as possible no one is asked to bear burdens disproportionate to the cumulative savings he/she/it realizes." NRDC advocates against criminal penalties in the enforcement of such programs, but rather suggests the imposition of civil fines equal to the full replacement cost of the electricity which the inefficient structure or process uses. NRDC emphasizes that any mandatory program should also include commercial and industrial structures and processes. An audit program for such sectors could be established and funded by a State commercial and industrial auditing bureau funded through an excise tax on energy sales to commercial and industrial customers. NRDC recognizes the difficulties of "fitting equitable standards to diverse Northwest industries" and suggests that regulators should first focus their attention on the aluminum industry. The form of residential, commercial and industrial mandatory retrofit programs should go beyond limited cost-effectiveness standards. NRDC is critical of the Portland program in that it requires the adoption of only those efficiency improvements that will pay for themselves over a 5-year period in that building. NRDC advises standards which are based upon the avoidance of high marginal costs of new generation far beyond a 5-year period. This would lead to a significantly increased energy efficiency of existing buildings. To avoid the appearance of requiring building owners to spend more to save energy than they would spend in the Northwest on the energy itself, NRDC advises the establishment of financing mechanisms which "spread the cost of truly cost-effective measures over the entire group that benefits from their adoption." Cost spreading through taxes and electricity bills are mentioned.

State energy policies are suggested which are based on the principle that no State action should be taken which will increase demand for conventionally generated electricity without first exhausting the potential for cost-effective conservation, renewable resource applications, and generating resources utilizing waste heat. Powerplant approvals, the design or remodeling of State and local government buildings, and the installation of street lights would all come under this standard. Life-cycle cost analyses should also precede construction or renovation of State buildings and the licensing of energy facilities.

NRDC supports the concepts of prohibiting new electrical hookups to inefficient structures and the prohibition of new electrically heated swimming pools. A suggested alternative to such restrictions would be a State-imposed surcharge on rates for electricity used in inefficient buildings or for inefficient processes.

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Attachment D

PLANNING ASSUMPTIONS

The following is a general discussion/description of three concepts fundamental to power system planning. These include system reliability, critical period planning, and the influence of the existing transmission grid.

In reading this material, it should be remembered that: (1) this discussion is not intended to represent a comprehensive evaluation of alternative planning assumptions or criteria, and (2) these particular assumptions are unaffected by the provisions of the proposal and alternatives contained in Chapter III, of this document.

1. Reliability and the Pacific Northwest Power Supply System. The reliability of an electric power system is a measure of its ability to adequately serve the customer. Although the concept of "adequate service" has different meanings depending on the ultimate use of electricity, most consumers expect electric power to be available 24 hours a day. However, the end-use consumer's expectation of certainty of power supply contrasts with some significant sources of uncertainty in the generation and delivery (both bulk transmission and distribution) of power by the power supply system. Reliability refers to the power supply system's responses to these uncertainties.

There are three principal sources of uncertainty for the Pacific Northwest power supply system. First, the annual runoff in the hydro system varies widely from year to year, but there is not enough storage to hold surplus flow so as to guarantee average flows in below-average water years. Thus, good water years result in plentiful runoff for generation, but low water years provide reduced generation potential. The second source of uncertainty is that generation or transmission facilities may not be available when needed, due to forced outages or construction delays. And third, unforeseen changes in power demand may arise, due to the uncertainty inherent in load forecasts. These three sources of uncertainty - water, resource dependability, and loads - are predominant in determining the reliability of the regional power system, both in theory and in practice.

a. Responses to Uncertainty. In order to provide reliable service, the power system must make allowances for these uncertainties. In the case of hydro runoff, power planners assume that there would be only as much firm energy as could be generated under the worst case conditions in the historical record, generally referred to as the critical water assumption (Role DEIS: A,IV-26-49). Energy above this amount is not assumed to be available every year. The critical water assumption identifies the minimum firm energy and capacity which can be made available with a specified high probability, based on flow records covering every year of the past several decades. (See critical period planning below.)

The power system generally allows for outages or delays in power facilities and load uncertainty by maintaining reserve capacity for generation and transmission. More generation, transmission, and distribution facilities are built than are actually necessary to meet expected instantaneous and annual energy and peak demands. This additional capability provides a margin for those times when some facilities are unavailable, or when the load is larger or streamflow is less than planned. Reserves for long range planning are calculated as a fraction of total system load rather than being associated with specific components within the system, because any component may serve partly or totally as reserve capacity at one time or another, and no system component is added solely for use as reserves.

In theory, the above responses to uncertainty should be based on detailed calculations of the probability of loss of load (i.e., the probability that demands will be greater than the system's ability to deliver power). Given the probabilities of various factors such as streamflow levels, the different causes of component failure, adverse weather, natural disasters, and other effects on the generation and delivery of power, it is possible to calculate the true probability of load loss for various combinations of assumed hydro energy, equipment redundancy, and component reliability.

In practice, it is not possible to make such a comprehensive assessment. As far as possible, loss of load probabilities are used to establish reliability criteria, but information and techniques for quantifying reliability are still developing. Thus, at present, criteria are also based on engineering judgment of the likelihood of system disruption or failure. The basic standard on which generation reliability criteria are based is that the annual probability of a loss of load on the system should not be greater than 5 percent. Nationwide, transmission reliability is based on contingency criteria.

In detail, each power system is unique. Many types of events are possible which can affect either the probability of a loss of load or the magnitude of its consequences. The probabilities of some of these events may be known, but many are not, and even where an estimate may be possible, records sometimes are not available to aid in making such an estimate. In addition, conditions affecting the power system are constantly changing, both locally and regionwide. Even if all of the various factors were well known, constant updating of information would be necessary to take changing conditions into account. In practical terms, a more simplified approach is required.

The basis for present reliability standards is a variety of formal agreements, contracts, and criteria, such as the Pacific Northwest Coordination Agreement, and BPA's "Reliability Criteria for System Design and Minimum Operating Criteria." These criteria are based on calculations of the probability of loss of load (generation), contingency criteria (transmission), operational experience, and knowledge of system characteristics. These documents specify standards of acceptable performance from the power system as a whole and from its component utilities.

Reliability criteria do not guarantee continuous service under all possible conditions; rather, they establish requirements which the power system must meet under different contingencies. In some cases, certain loads may be disconnected, resulting in outage impacts, to avoid worse consequences of a system failure. Ideally, the probabilities associated with reliability criteria and the costs of their associated configurations of facilities would be compared to the costs of potential shortages or outages in terms of health and safety, economic production, environmental impacts, and other costs affected by outages, including remedial or mitigating actions. The comparison of costs would then provide a basis for selecting an optimum level of reliability. In practice, though, the general criterion used is basically that the lower the probability of the contingency, the more severe the acceptable consequences. This relationship is shown in Figure 1. Reliability criteria define capabilities the system must have to keep the consequences of adverse situations within an acceptable range.

b. Alternative Reliability Methods and Standards. There are two ways to change reliability: by changing the method of achieving a given level, or by changing the levels or standards. Either type of change could be accomplished by altering assumptions, changing the degree of redundancy in the system, or using different standards of component reliability.

The relationship between the costs of achieving a given level of reliability and the level of reliability reached is not linear. Stated differently, each additional increment of reliability is more costly than the last. Initially, expenditures for facilities provide large improvements in reliability, but as reliability becomes better, additional expenditures make decreasing gains in reliability. Thus, varying the level of reliability may not lead to proportionate changes in costs of facilities. This relationship is shown in Figure 2. Current regional reliability is high; thus, changes from present reliability would have varying costs.

The selection of reliability levels is further complicated by the fact that there is no single systemwide level of reliability. Outlying areas are subject to less stringent reliability requirements than are load centers. Distribution systems are less reliable than bulk transmission due to the many individual lines required for distribution. Vital services such as hospitals tend to receive priority over residences. These differences conform generally to the relationship illustrated in Figure 1, namely that the more severe the unacceptable consequences, the lower the probability of the contingency. However, a change which affects reliability throughout the system may not affect these different users equally, or even proportionally.

There are some institutional constraints in setting reliability standards. Some standards are contractually binding, and others are established by unanimous agreement among utilities or utility reliability councils; thus, a change would require a convincing demonstration of the cost-effectiveness. Operation of a power system is sufficiently complex that it would be difficult to unequivocally demonstrate the merits of a general change in reliability standards.

c. <u>Transmission Reliability</u>. The transmission response to uncertainty takes the form of redundancy and high component reliability. Present day transmission reliability standards have evolved from probabilistic engineering judgments about system failures and their effects. In order to quantify the relationships between the frequency, severity, and acceptability of system failures, additional analysis is required. This analysis should include data on outages (failure rates, repair times, failure modes, etc.), customer interruptions, and costs of interruptions.

Transmission reliability does not come in small increments. When reliability is sufficiently low at some delivery point that facilities must be improved, a large-scale project is ordinarily most cost-effective. This project is generally designed to provide sufficient reliability at that delivery point for long-term needs, for example, 15 to 20 years. Consequently, the delivery point reliability is changed from minimal to substantially more than optimum for current requirements due to the quantum nature of transmission system additions.

Present levels of component reliability are quite high. Redundancy in the transmission system is specified according to the size of the line and the effects on the system of contingencies affecting the line.

Higher reliability levels can be obtained by increasing component reliability, redundancy, or both. Increasing component reliability is primarily an economic question. However, environmental consequences might result, especially if changes in design were adopted affecting land-use requirements for transmission lines, such as increased clearances, more use of overhead ground wire, or greater separation of common right-of-way structures. The impacts of increased redundancy are more right-of-way, substation sites, access roads, etc. (Role DEIS: B,III-24-27).

Increased component reliability might arise from improved or more easily maintained equipment, or operating procedures with less chance for human error. The issues which must be addressed to determine if this method of changing reliability is cost-effective are the potential for improvement, the system consequences of component improvement, and the cost of improvement. There is a tradeoff here between research and development to improve existing equipment and research and development on new technologies.

The value of improving component performances depends on the marginal cost of changing equipment performance, and the marginal system benefit from changing component reliability. Improved data on these costs and benefits are objectives of current research efforts.

A change in redundancy of the transmission system probably would have a larger effect on customer reliability than an increase in component reliability because component reliability levels are already high. This means that substantial improvements in component reliability probably would be needed to give modest reductions in redundancy requirements.

If the standards for the transmission system reliability requirement were to be reduced, the present system would be more redundant than necessary initially and there would be a decrease in the immediate need for new facilities. After this excess was assigned to meeting requirements of growing electrical demands, there should be a delayed need for the same type of equipment. Thus, the main result would be to slow down the addition phase and to correspondingly delay the environmental impacts. This would allow added time for the development of new technologies and better determination of the need for additions to the system. On the other hand, the reduced system reliability would at times result in system disruptions, more individual customer outages, and probably a reduced emphasis on development of new technology.

Another way to improve transmission system reliability and to reduce the cost of service to the consumer is through the use of system interconnections among utilities. Interconnections among separate power systems and the coordination of their planning and operation are discussed in the Draft EIS (Role DEIS: A,II-21-26 and in Chapter IV.B.1. in Volume 1 of this document).

Standards which are closely associated with localized customers rather than large areas are the customer service reliability criteria (Role DEIS: B,III-17-24). Other aspects of the reliability criteria are concerned with increasing system reliability by increasing component reliability (Role DEIS: B,III-24-27).

d. Generation Reliability. Generation reliability and load forecasts are currently calculated for two time spans; the short-term (operating program) and the long-term (long-range planning).

The reliability level and method set forth in section 8 of the Pacific Northwest Coordination Agreement (PNWCA) is the standard used by the Pacific Northwest utilities. This probability of load loss method calculates the minimum reserve margin necessary to maintain an annual probability of load loss equal to 5 percent and the resulting firm peak load carrying capability (FPLCC) of each system (Role DEIS: 1,II-37 and A,IV-49).

Long-range planning studies use the larger of minimum reserve margins specified by PNUCC, plus one half year's utility-type load growth and maintenance, or the PNUCC criterion of 12 percent through 20 percent of the system peak load increased by 1 percent per year (Role DEIS: 1,II-37 and Chapter IV.A of Volume 1 of this document). The use of a minimum reserve margin for the operating program applies except when the percentage limits are involved. Once the percentage rule is in use, only methods which change the peak load will affect the minimum reserve margin. For example, diversity capacity exchanges would reduce the winter peaking load and reserve requirement, but would increase the peaking load and reserve requirement in the summer.

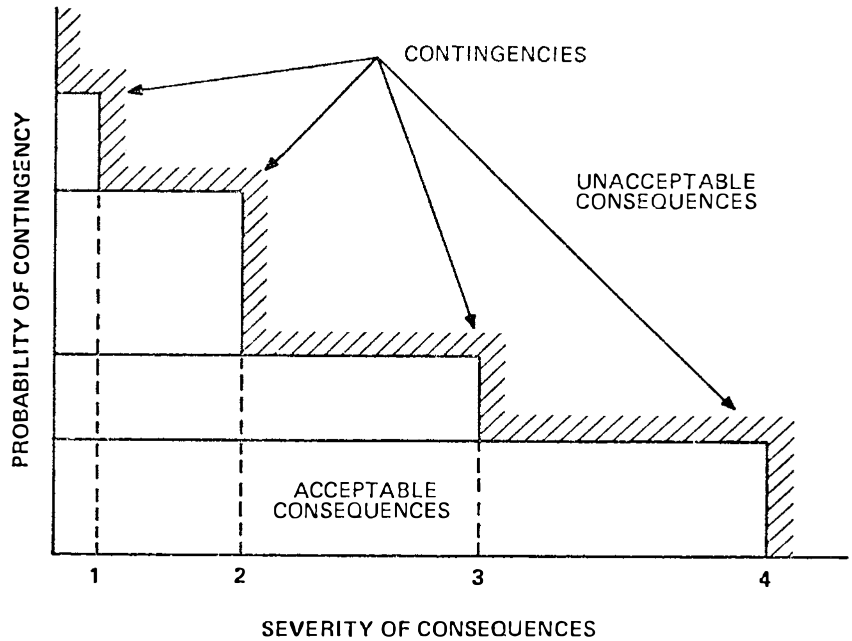

Figure 1

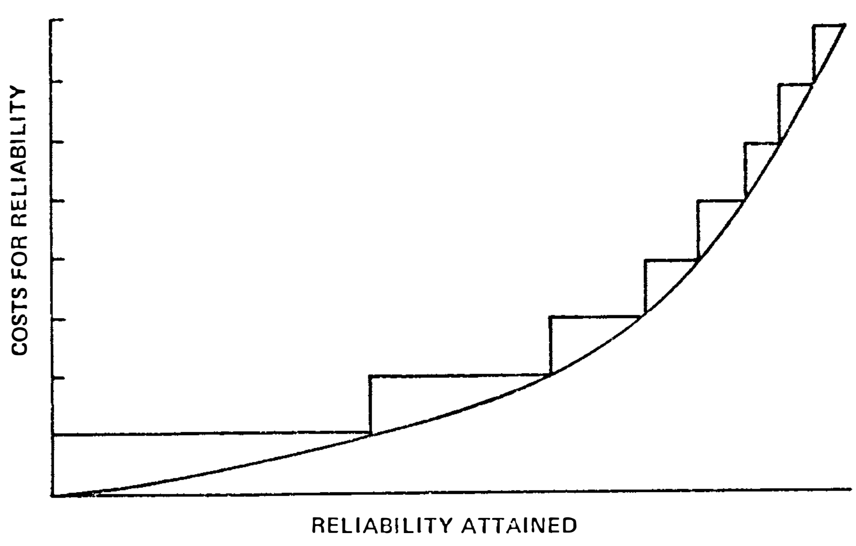

Figure 2

hydro system at any time provided the region does not experience streamflows more adverse than in the past.

When the hydro generation thus derived is combined with the expected thermal generation, the sum effectively defines the firm loads that can be served. Statistically, the critical period planning criterion produces a reliable power supply, providing that firm energy loads are in balance with firm energy capability of the system (which includes components of both hydro and thermal generation). At times when actual streamflows are better than those in the historical critical period, the system will be able to produce energy in excess of its firm energy capability. This excess is considered nonfirm or secondary energy.

Recent hydro regulation studies use the 42½-month period of August 16, 1928, through February 1932, to define the critical planning period for the amount of storage existing in the 1970s.

As a measure of the reliability of the firm energy supply, one can look at the probability of recurrence of the critical year streamflows. BPA engineers have estimated that the average recurrence interval for the 42½-month critical streamflow period was on the order of once every 300 years (Role DEIS: A,IV-29). They estimated that a 20½-month sequence of streamflows, such as that which occurred in 1943-45, produced a firm energy load carrying capability essentially the same as the capability produced by the 42½-month sequence. Hence, the 20½-month flow sequence could effectively define the firm load carrying capability of the hydro system as well as the 42½-month sequence defines the capability. BPA also demonstrated that the recurrence interval of these 20½-month streamflows was considerably more frequent that those in the 42½-month period. The calculations indicated that the 20½-month critical flows has a recurrence interval on the order of once in 60 years compared to the approximately once in 300 years for the 42½-month streamflow event. Hence, the risk that actual streamflows will be less than those used for firm load planning is effectively about 1 in 60 (about 2 percent) in any 20½-month period chosen at random.

It is important to stress that the risk of occurrence of a critical water year is a measure of the reliability of the power supply only to the extent that there is a balance between firm loads and firm resources. Delays in the completion of thermal projects or loads exceeding the estimate, for example, also affect reliability and could result in load/resource imbalances.

Criticism of the critical period planning criterion has generally been that the criterion is too conservative and that more risks should be taken with the regional power supply. Since streamflows are frequently greater than critical, why not serve loads that are normally firm with this energy and curtail these loads during rare periods of drought? The advisability of accepting a planning criterion less reliable than that defined by the critical period method rests on the magnitude and frequency of adverse socio-economic impacts that would occur during periods of shortage.

The effects of increasing component reliability are analogous to those discussed under transmission reliability. Components are highly reliable at present; thus, large increases in component reliability would result in only modest improvements in system reliability, but decreases in component quality could significantly degrade system reliability.

If a lower reliability level were adopted, the annual probability of load loss would increase (Role DEIS: A,IV-52). New resources would be delayed, resulting in a corresponding delay in environmental impacts. This would allow added time for the development of new technologies. On the other hand, there would be a higher risk of large system disruption and individual customer outages, and due to the reduced urgency of need for facilities, there could be a reduced emphasis on development of new technology.

For example, use of a less restrictive planning assumption than the critical water year would increase the planned firm hydro generation, reducing the necessity for more thermal generation. Because of the reduced use of thermal generation, system reliability would increase. However, the load loss method used in the Pacific Northwest does not consider the probability of a given water condition occurring. Thus, by choosing a better than critical year, the probability of having a water year worse than assumed for planning is larger and the resultant system reliability is decreased, counterbalancing the increased reliability due to lessened dependence on thermal generation (Role DEIS: A,IV-26-49).

2. Critical Period Planning. The Federal operating agencies and the region's utilities have historically cooperated in long-range power planning. Each year these planning efforts result in the West Group Area Forecast of Power Loads and Resources compiled under the auspices of the Pacific Northwest Utilities Conference Committee (PNUCC). Associated with this planning effort has been an agreement by the parties on a set of basic planning assumptions, which include the use of critical water (streamflow) as the basis for calculation of the firm energy capability of the system. This planning criterion has been formalized in a Coordination Contract among the parties and has resulted in a reliable power supply over the years.

Power resources engineers have defined the critical planning period based on information derived from the 40-year historical streamflow record from July 1928 - June 1968. The critical period is defined as that interval of the 40-year historical streamflow record which, when combined with draft of all available reservoir storage, will produce the least amount of energy from the total coordinated power system. In these calculations, all reservoirs are assumed full at the beginning of the critical period and are drafted empty along a seasonal operating pattern by the end of the critical period. In summary, occurrence of the critical period streamflow sequence, when combined with reservoir storage, will produce an amount of energy defined to be the firm energy load carrying capability of the hydro system. This is essentially the energy which can be guaranteed for delivery from the

In an attempt to better evaluate planning criteria, steps are underway at BPA and within the utility industry to quantitatively define the socio-economic impacts of shortages of electricity. New methods are developing for attempting to define the least-cost reliability criteria by analyzing the tradeoff between the cost of increased reliability and the cost of shortages. For example, the Electrical Power Research Institute (EPRI) has several research contracts that attempt to analyze the cost of overbuilding or underbuilding generating capacity. BPA is presently investigating the usefulness of a capacity expansion model developed by Decision Focus, Inc. (DFI) for EPRI. (Costs and Benefits of Over/Under Capacity in Electric Power System Planning, EPRI EA 927) The DFI model allows for the variability of all streamflow conditions and for the uncertainty in load forecasts and thermal plant performance. Therefore, the model does not plan resources on the basis of critical water conditions, but incorporates the uncertainty of the total resource generating system and offsets this with the cost of outages or shortages. The model does not determine what streamflow assumption should be used, but it does determine the overall generation reliability which minimizes the costs, both social and economic, to consumers. Preliminary results from this model indicate that, given the existing system, the use of current planning reliability criteria (using critical water assumptions) tend to produce a capability expansion plan which is in the range of total lowest rates and outage costs to the consumer.

The DFI model, although conceptually correct, has yet to be thoroughly tested for this region. Preliminary tests of the model have disclosed a few problems. Major problems are: (1) allowing for the flexibility of hydro storage capability; (2) the inclusion of pumped hydro storage; and (3) the quantification of the cost of an outage or shortage in our region. However, work is currently underway to correct these and other deficiencies. The revised model may serve as an input to BPA and the PNUCC planning committee efforts in the review of present planning processes.

Even though the current critical period planning criterion may not be changed as a result of these studies, there could be ways to firm up some of the Pacific Northwest secondary energy, such as construction of additional combustion-turbine generators for use during occasional drought periods when secondary energy is not available for use by Northwest firm power customers. The feasibility of this arrangement from an economic and environmental point of view is being investigated at BPA. However, because combustion-turbines are currently fueled by either gas or oil, their feasibility could be complicated by the National Energy Act, which places restrictions on the use of these fuels.

In summary, use of the critical water planning criterion in use by BPA and Northwest utilities results in a high degree of assurance that the hydro generating system will produce at least the planned amount of firm energy carrying capability. Accordingly, the region's firm load is likely to be reliably served, provided that a condition of balanced loads and resources exists. However, unanticipated load growth and slippages in the completion dates of new generating plants can substantially reduce system reliability. Further, the reaction of residents of the Northwest to a reduced power supply reliability must be determined. Assessments of these matters are presently underway.

3. Influence of the Existing Transmission Grid on Power System Development. BPA currently operates and maintains approximately 12,500 miles of long-distance high-voltage transmission facilities. This system constitutes about 80 percent of the high-voltage transmission capacity in the Pacific Northwest. These facilities represent an extensive grid serving Oregon, Washington, Idaho, and western Montana. In addition, the transmission system also ties in with other regional systems to the north and the south.

Generally, because of its extensiveness and capability, the transmission system has not presented any obstacles to the development and location of generation facilities. In fact, the very extensiveness of the main grid can be said to have facilitated or enabled construction of large-scale central station generation in areas remotely located from load centers. Although transmission costs are a significant component of resource development costs, they are not usually the critical factor. For example, in locating a coal-fired power plant, transmission costs are greatly overshadowed by the availability of cooling water and fuel transportation costs. Thus, an extensive transmission grid enables utilities to make optional location decisions.

To date, the consequences of the extensive high-voltage transmission system upon the development of generation resources have been twofold. First, because the transmission system serves to integrate a coordinated regional power system, it facilitates the construction of large plants which take advantage of economies of scale. Second, because the existing transmission system is extensive, new resources can be easily integrated, while costs of additional transmission are minimized.

In the future, the transmission system will also serve to facilitate the development of small-scale technologies by allowing the existing hydro system to serve as a backup to intermittent generation resources, such as wind generation or other solar energy resources.

There are no practical alternatives to the continued utilization or reliance upon the existing transmission system. To do so would lessen overall system efficiency and run contrary to the "one-utility concept" in that more transmission facilities would be constructed than would otherwise be necessary.

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