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Bonneville
Power
Administration

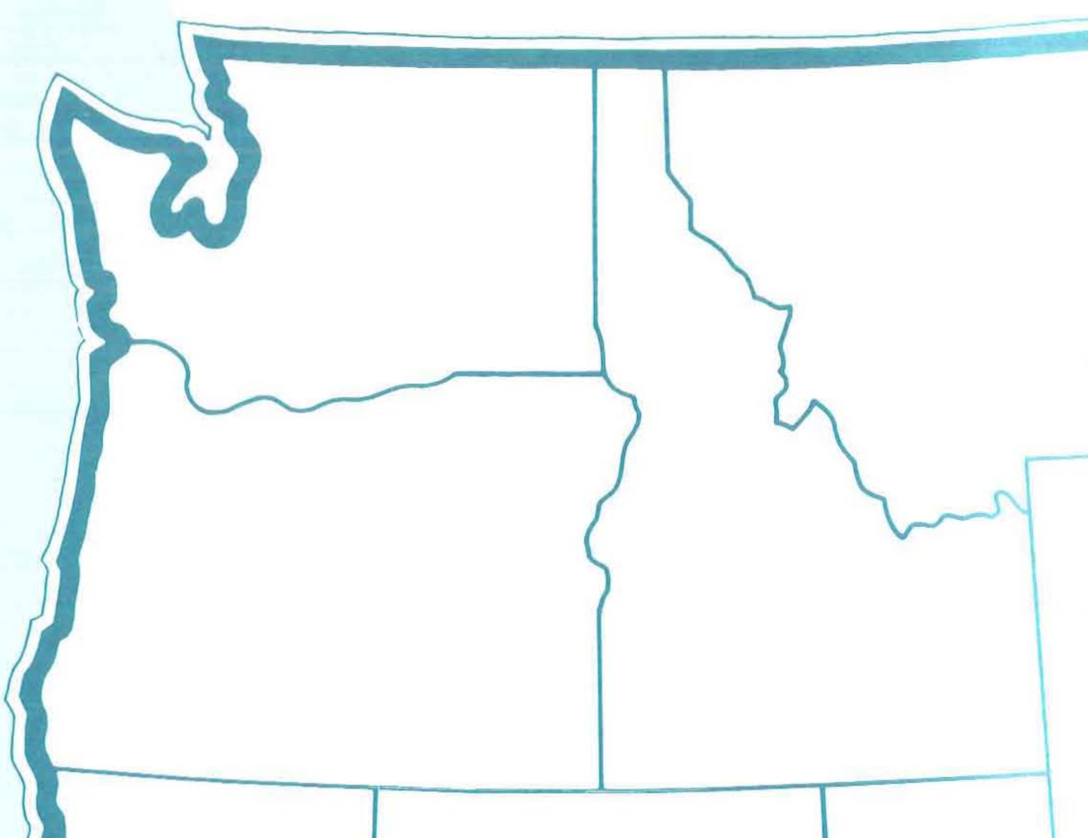
Final Environmental Impact Statement

INITIAL NORTHWEST POWER ACT POWER SALES CONTRACTS

U.S. Department
of Energy

January 1992

Volume 1:
Environmental
Analyses



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FINAL ENVIRONMENTAL IMPACT STATEMENT

Responsible Agency: U.S. Department of Energy, Bonneville Power Administration (BPA).

Title of Proposed Action: Initial Northwest Power Act Power Sales Contracts.

Cooperating Agencies: None.

States Involved: Washington, Oregon, Idaho, Montana, Wyoming, Utah, California, Nevada.

Abstract: In 1981, BPA offered its customers long-term contracts pursuant to the requirements of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). BPA published a Final Environmental Report to accompany the initial contract offer but did not prepare an Environmental Assessment (EA) or an Environmental Impact Statement (EIS). In 1981, an environmental group, Forelaws on Board, charged that BPA's failure to prepare an EIS on the offered contracts violated the National Environmental Policy Act (NEPA). In 1984, the United States Court of Appeals for the Ninth Circuit ordered BPA to prepare an EIS, but allowed BPA and its customers to continue operating under the contracts.

- Since the Court's Order left the contracts in place, the EIS has been used to inform BPA, customers, the Northwest Power Planning Council (Council), and the public of the potential environmental consequences of the contracts and will guide future actions. The EIS provides a midterm evaluation of these existing contracts to determine if they should be preserved or changed. Thus, this EIS is the first stage in a two-stage process. The first stage is completion of the EIS with the selection of the preferred alternative, i.e., the development of a BPA policy for enforcement of the Council's Protected Areas Rule. The second stage is the development of the BPA policy. Because the proposed policy implements the preferred alternative through noncontractual means, it does not require either amendment or renegotiation of the existing power sales contracts.

- The EIS analyzes BPA's two broad alternatives: first, to preserve the contracts without change (the No Action Alternative) or, second, to pursue modifications. Within the second alternative are five categories corresponding to major policy issues: (1) hydro development and operations; (2) conservation; (3) resource planning and development; (4) quality of service as a resource choice; and (5) industrial load constraints. Each category encompasses a range of possible changes. The alternatives all are compared with the No Action Alternative. The 18 individual alternatives examine discrete issues in the contracts and are thus generally not alternatives to each other. Also, for that same reason, the types of impacts reported are very diverse. Summarized extremely briefly, the draft analysis for all but one alternative did not indicate that significant environmental benefits would be gained by negotiation of reasonable alternative contract provisions. The exception is Alternative 1.1 for which draft analysis indicated potential environmental benefit from increased implementation of the Council's Protected Areas rule regarding new hydro resource development.

- BPA has selected the Protected Areas element of Alternative 1.1 as its preferred alternative in the final EIS. Under the preferred alternative, the second stage of this process, the policy development process, will be conducted following completion of the Final EIS and Record of Decision. The existing contract provisions represent policy choices on the appropriate roles of BPA and its customers and others under the Northwest Power Act. With the exception of the proposed policy development, after nearly 10 years of operating under the existing contracts, BPA remains generally comfortable with those decisions.

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SUMMARY

EXECUTIVE SUMMARY

Background. This Final Environmental Impact Statement (EIS) examines the environmental effects of the power sales and residential exchange contracts issued by Bonneville Power Administration (BPA) in 1981, as required by the 1980 Northwest Power Act. These contracts provide electric power service to BPA's utility customers--publicly owned and investor owned--and its Direct Service Industrial customers. BPA is preparing an EIS on the contracts to help decide whether to seek changes in the contracts, take other actions with respect to the issues, or take no action. This EIS was ordered by the U.S. Court of Appeals for the Ninth Circuit in the case of Forelaws on Board v. Johnson, 743 F.2d. 677 (9th Cir. 1984).

Two-Stage Process. The Court Order noted that the EIS results could be used to guide future contract negotiations which might require their own analysis under the National Environmental Policy Act (NEPA). Such future contract negotiations could deal with amendments to the current contracts or terms for new contracts.

BPA's process therefore consists of two stages. This EIS is Stage One. This EIS examines the environmental effects of the current contracts in broad policy areas. Stage One ends with BPA's Record of Decision on this Final EIS, which is expected to formalize BPA's decision to develop a Protected Areas policy to obtain the environmental benefits identified for Alternative 1.1 in the EIS. Stage Two will start with public notices of development of a BPA Protected Areas policy. Because a Protected Areas policy would not require changes in the terms of BPA's power sales contracts, it would not require negotiation with BPA's customers.

Alternatives. There are 18 alternatives divided among five major policy categories:

1. **Hydro Operations and Development** looks at the effects of the contracts on hydroelectric dams.
2. **Conservation** looks at the effects of the contracts on electric power conservation efforts, such as insulating buildings. The Northwest Power Act requires BPA to treat conservation as a resource for "serving" electric power loads, just as power plants are resources.
3. **Resource Planning and Development** looks at the effects of the contracts on the way BPA and its customers plan future conservation efforts and power plants.
4. **Quality of Service as a Resource Choice** looks at how contracts can allow for interruption of electric service as an alternative to building power plant resources.
5. **Industrial Load Constraints** looks at how the contracts can promote or discourage the growth of industries that depend heavily on electric power.

How the Analysis is Structured. The analysis in Chapter 2 first explains what the contracts provide and how they work with respect to the five major policy categories.

The alternatives concern widely different questions, so different study techniques were needed. Some alternatives are analyzed qualitatively, while others are analyzed with computer models. Each alternative is compared to the No Action Alternative, which is the current contracts.

Preferred Alternative: The Protected Areas Element of Alternative 1.1.

The Preferred Alternative means keeping the current contracts as they are, while obtaining the environmental benefits of enhanced enforcement of the Protected Areas Rule through development of a BPA policy to enforce the rule. One of the most controversial issues for the Draft EIS was whether existing contracts should be reopened for specific changes. The existing contract provisions represent BPA policy choices not just on technical details but on its role and the roles of its customers and others under the Northwest Power Act. After several years of operating under the contracts, BPA does not believe that there is a need to reconsider those decisions. Comments received on the Draft EIS indicated that several parties favor provisions to help fish and wildlife. Based on these comments, BPA changed the preferred alternative from the No Action alternative to the the Protected Areas element of Alternative 1.1.

Summary of Alternatives, Analysis and Results. The following section contains brief synopses of important questions on environmental impacts of alternatives with short answers. BPA invites comment on the completeness of these summaries.

CATEGORY 1: HYDRO DEVELOPMENT AND OPERATIONS ALTERNATIVES

Alternative 1.1 Fish and Wildlife Compliance as a Condition of Service

QUESTION: Would BPA's utility customers take more action on measures from the Northwest Power Planning Council's (Council) Fish and Wildlife Program if the power sales contracts required customers to abide by the Fish and Wildlife Program? Now, fish and wildlife obligations are applied to BPA utility customers through licenses for dams, which are under the jurisdiction of the Federal Energy Regulatory Commission (FERC).

ANSWER: The alternative is not likely to significantly affect the environment via the Council Fish and Wildlife Program measures that are aimed at the fishery impacts of existing dams. The alternative might help measures directed at new dams, namely the Council's Protected Areas rule, which limits hydro development in certain stream reaches. Action on wildlife measures would not be changed because the Council's current list of wildlife measures does not require utility implementation.

Alternative 1.2 No Use of Borrowing Techniques for Direct Service Industries (DSIs) First Quartile Service

QUESTION: Would operation of Federal Columbia River dams change if BPA did not draft certain amounts of water from reservoirs to serve part of the power load of its DSI customers?

ANSWER: Dam operations would not change significantly and therefore no significant environmental effects are foreseen. The same amount of water would probably be drafted from the same reservoirs for other purposes, such as short-term sales of electric power. DSIs could be harmed by this alternative, since it would increase the chance that their electric power could be interrupted. If the harm were economically serious, DSIs might reduce production or close. This would reduce BPA's need to invest in conservation or power resources but could hurt local economies.

Alternative 1.3 Limit Firm Load Changes Within Operating Year

QUESTION: Would Northwest power resource operations change if BPA's customers had lesser contract rights to make short-notice changes in the amounts of power they wished BPA to supply? For example, if a utility's load increased or decreased suddenly, or a DSI's need for power changed, what would happen if that customer had to deal with the short-term change without help from BPA?

ANSWER: Northwest power resource operations would change somewhat, because customers would run their own power plants instead of purchasing power from BPA's plants. BPA's existing power plants are primarily hydroelectric dams, while other Northwest utilities generate more of their power with thermal plants. Therefore, this alternative could result in different types of environmental effects due to operation of existing power plants, but these differences are unquantifiable. In addition, the resources planned for the future would probably be different, since BPA's resource plans contain more conservation programs and less thermal plant development than the plans of other Northwest utilities. The environmental impacts of different types of resources are discussed for Alternative 3.2 below.

CATEGORY 2: CONSERVATION ALTERNATIVES

Alternative 2.1 Conservation Compliance as a Condition of Service

QUESTION: Would more conservation be developed in BPA customer service areas if customers were required by the power sales contracts to take action to achieve certain levels of conservation?

ANSWER: No significant environmental effects are projected because there would be no change in the amount of conservation in the loads BPA serves. Utilities that purchase most of their power from BPA would continue their current high level of participation in BPA conservation programs. No change is expected for investor-owned utilities (IOUs) either, since they will continue to acquire cost-effective conservation in accordance with least-cost planning principles.

Alternative 2.2 Conservation Transfers Facilitated

QUESTION: Would there be more conservation achieved in the Pacific Northwest if BPA customers could enter into "conservation transfers" with each other? A conservation transfer could be accomplished by Utility A funding conservation programs in Utility B's area, while Utility B transfers to Utility A an amount of firm power that Utility B receives from BPA equal to the amount of energy savings achieved by the conservation programs. Under the current requirements contracts, BPA's utility customers must use the firm power they buy from BPA only to serve their loads and cannot resell it as a commodity.

ANSWER: There might be more conservation achieved under the alternative in some scenarios, but this is uncertain, therefore no significant environmental change is projected. On the other hand, the alternative would certainly raise difficult legal and policy questions which do not necessarily affect the environment: resale of BPA's firm power to other entities could dilute preference customer priority rights to certain BPA resources (called Federal base system resources) by essentially allowing IOUs to gain access to these resources through the transfer. It also would be inconsistent with the purpose behind the statutory 5-year cancellation provision that must be included in BPA contracts with IOUs so that power may be withdrawn from IOUs if it is needed for preference customers.

CATEGORY 3: RESOURCE PLANNING AND DEVELOPMENT ALTERNATIVES

Alternative 3.1 BPA Load Placement Certainty

QUESTION: Would BPA's planning of future conservation and generating resources be different if BPA had 10-year notice of customer needs rather than the current 7-year notice?

ANSWER: The effect of 10-year notice versus 7-year notice is unpredictable, but no significant environmental changes are projected. A longer notice requirement could induce customers to seek power from sources other than BPA, so BPA would have less obligation to plan future resources. If customers continued to buy from BPA, the 10-year notice would not significantly change the types of resources BPA would develop. In some scenarios, the extra notice could increase the chance that BPA would decide to complete Washington Public Power Supply System Nuclear Plants (WNP)-1 and -3 or develop other large thermal plants.

Alternative 3.2 BPA as Regional Supplier

QUESTION: Under the current contracts (and the Northwest Power Act), BPA's utility customers are free to develop their own conservation and power resources. Would there be significant differences if Northwest resource development were controlled centrally under BPA?

ANSWER: The alternative could have significant environmental effects under some scenarios, but the regulations and policies applying to the siting of generating resources in the Northwest are changing. Utility rights to plan and acquire resources independently are protected by section 10(a) of the Northwest Power Act. The effect of such independent development (compared to regionally centralized resource development by BPA) was studied by BPA and the Northwest Power Planning Council prior to this EIS. Centralized resource development by BPA was found to result in lower net regional costs due to increased conservation and use of Federal resources such as WNP-1 and -3 and firming of Federal nonfirm energy. In contrast, current information on independent utility resource development shows more use of renewable resources (such as small dams and cogeneration plants) and more coal plants. Utilities would probably not develop coal plants until after they pursue conservation and develop other lower-cost resources, however.

Alternative 3.3 Customer Planning on Other Than Critical Water Basis

QUESTION: What would be the effects on operation of Northwest dams and on development of Northwest power resources if the current contracts did not incorporate the criterion of critical water planning? BPA and other Pacific Northwest utilities that operate dams for power use a relatively conservative "critical water" planning standard to judge how much power can be generated on a firm basis with the annual water runoff. This standard tends to result in a smaller rating for the system's generating capability than a less conservative standard and, therefore, tends to encourage the development of more generating resources than would a less conservative standard.

ANSWER: There would be no environmentally significant changes. Critical water planning criteria are established and applied under the Pacific Northwest Coordination Agreement of 1964 (Coordination Agreement), to which BPA and its generating customers are parties. All customers who are parties to the Coordination Agreement would continue to be bound by its critical water planning provisions. Although the BPA contracts incorporate and refer to critical water planning criteria, they do not require customers to take actions to follow those criteria. The current contracts do, however, contain a disincentive against noncritical water planning--a charge that applies to customers (referred to in the power sales contracts as Actual Computed Requirements purchasers) that own and operate significant power resources. BPA customers that are not Actual Computed Requirements customers are not subject to this disincentive, but the majority of them continue to use critical water planning criteria. This supports a conclusion that the alternative would result in no significant changes.

Alternative 3.4 Improved Ability to Exercise Provisions to Make Purchases in Lieu of Exchanges

QUESTION: The Residential Exchange Agreements called for by the Northwest Power Act allow BPA to buy other resources instead of the customer's exchange power under certain conditions. Because these "in lieu" purchases can have economic effects on the exchanging customer, there are contract notice provisions and some other limitations that apply to BPA's use of this option. What would change if BPA were able to make purchases in lieu of exchanges more quickly than is allowed under the 7-year notice required by the current Residential Exchange Agreements?

ANSWER: The effects of the alternative are primarily economic and do not have significant environmental implications.

Alternative 3.5 Shorter Contract Terms (10 years)

QUESTION: Would there be any significant environmental effects if Northwest Power Act power sales contracts were limited to 10-year terms instead of the current 20-year terms?

ANSWER: DSIs would probably buy less power from BPA than under current contracts, because they would be significantly affected by the uncertainty of a shorter BPA contract term. DSIs customers might seek another power supplier that would offer longer-term certainty or might acquire their own generating resources. Environmental effects could stem from the types of resources developed to serve DSI loads. Utilities would probably continue to buy the same amount of power from BPA even with the added uncertainty of shorter contract terms, because they have continuing statutory rights to receive power from BPA.

CATEGORY 4: QUALITY OF SERVICE AS A RESOURCE CHOICE

Alternative 4.1 Increase First Quartile-Type Interruptibility

QUESTION: What would be the effects of increasing the amount of Direct Service Industry service that the contracts allow BPA to interrupt? Also, what would be the effects of interrupting service to other customers in a similar fashion?

ANSWER: When a contract allows service to a customer to be interrupted under certain conditions, that contract right is, in some respects, like a power plant held in reserve. When there is an unexpected need for more electric power, a supplier such as BPA can use these contractual reserves by turning off some load instead of turning on a power plant. DSI contracts provide reserves by giving BPA some rights to interrupt service and therefore take the place of a resource that would otherwise have to be bought or built. Utility contracts typically have not allowed this type of service interruption, although there is some possibility that they could in the future. This EIS and previous studies by BPA and others have shown that DSIs are harmed when their quality of service decreases significantly from current levels. A reduced rate for the lower quality of service would offset the harm to some degree, but there is a point where the frequency of interruption becomes too costly or impracticable for the industrial processes used by Direct Service Industries. Northwest industrial plants might be closed or production might be reduced if electric power supply were uncertain. The environmental effects of this alternative stem from reduced development of generating resources and potential socioeconomic effects of closure of industrial plants. There is little information at this time on the effects of interruptible service on customers other than DSIs.

Alternative 4.2 No BPA Purchase Required for Certain Exercise of First Quartile Restriction Rights

QUESTION: Would the operation of dams and other power plants change if BPA could interrupt DSI service without having to buy replacement power?

ANSWER: The alternative was found to have no effect on operation of dams or other power plants, because the same amount of customer load was generally served by the same resources in both cases. The current contracts require BPA to buy replacement power at prices up to "reasonable cost" before interrupting DSI service under certain circumstances. This cost is added to BPA's other costs and paid for generally by BPA rates. Under the alternative, DSIs would have to pay for the replacement power directly. This change in financial responsibility would have environmental effects only if DSIs could not afford the price for replacement power and therefore reduced production or closed their plants. It was not possible to quantify how often the cost of replacement power might be unaffordable to DSIs.

Alternative 4.3 Increase Quality of Service to First Quartile

QUESTION: What would be the effects of increasing the quality of service to DSIs so that BPA would be obligated to acquire resources for the entire Direct Service Industry load instead of three-quarters as under current contracts?

ANSWER: This alternative probably would require changes in laws addressing BPA service to DSIs. It is included to provide contrast to the other alternatives that look at effects of lower DSI quality of service. Under the alternative, BPA would have to develop conservation and new power resources more quickly than under the current contracts. Operation of dams and other power plants, and, therefore, the environmental effects, will not change significantly.

Alternative 4.4 No DSI-Type Reserves

QUESTION: What would be the effects of canceling the current DSI contract provisions that allow service to be interrupted?

ANSWER: As explained under Alternative 4.1 above, contract rights allowing service interruptions are similar to power plants held in reserve. If current DSI contract provisions were canceled, BPA would have to replace the reserves with other resources, such as combustion turbines, or interruptibility arrangements with other customers. Combustion turbine environmental effects are described in an appendix. The environmental effects of other interruptibility arrangements cannot be identified until the specific conditions are known.

CATEGORY 5: INDUSTRIAL LOAD CONSTRAINTS ALTERNATIVES

Alternative 5.1 Larger DSI Firm Load

QUESTION: Would BPA plans for development of conservation and power plants change if DSI load could grow larger than allowed under current contracts?

ANSWER: Additional DSI load growth might cause BPA to develop resources to meet load growth. If some of the contract limitations were loosened, DSI load in 2001 could grow by approximately 700 MW, or 19 percent more than current projections. BPA plans its future conservation and power plants in its Resource Program processes by using a "resource stack" showing the relative cost-effectiveness of different types of resources. The environmental effects of different types of resources are described in an appendix.

Alternative 5.2 Smaller DSI Firm Load

QUESTION: Would BPA plans for development of conservation and power plants change if DSI load growth were more strictly limited than under current contracts?

ANSWER: DSI firm load for which BPA must acquire resources could be smaller by approximately 7 percent by 2001. This would not significantly change the amounts or types of resources developed by BPA.

Alternative 5.3 Remove New Large Single Load (NLSL) Constraints

QUESTION: Would electric power use by new large industrial facilities (other than DSIs) increase if BPA were not required to charge a higher rate for such loads?

ANSWER: The current power sales contracts require a higher power rate for new industrial developments that use 10 average megawatts (aMW) or more per year. The Northwest Power Act calls these NLSL. The higher rate is based on the incremental costs of new resources.

Removal of the higher rate requirement would increase Northwest industrial load growth. BPA resource needs would grow by approximately 290 MW. As explained for Alternative 5.1 above, this could cause BPA to acquire some of the the resources in the next level of its resource stack a few years earlier than without such load growth. Environmental impacts could occur due to construction of new industrial plants and to the chemicals and processes used. The greatest growth was forecast to occur in the pulp and paper industry. However, impacts would be limited because air, water, land and other effects of industrial processes are subject to Federal, State, and local regulation.

Alternative 5.4 Increase NLSL Constraints

QUESTION: This alternative is the inverse of Alternative 5.3. Would electric power use by industrial facilities decline if the higher rate applied to any industrial load growth, not just single facilities using 10 aMW or more?

ANSWER: Regional industrial load growth would be a little smaller than under existing contract provisions. BPA's resource acquisition needs would be decreased by between 73 and 116 MW by 2008, an insignificant amount. A portion of this decrease in new industrial load would be due to use of other fuels instead of electricity.

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CHAPTER 1

Purpose of and Need for Action

CHAPTER 1

PURPOSE OF AND NEED FOR ACTION

1.1 Introduction

In 1981, Bonneville Power Administration (BPA) offered its customers long-term contracts pursuant to the requirements of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). BPA is now analyzing the environmental impacts of these contracts in an Environmental Impact Statement (EIS), as required by the National Environmental Policy Act (NEPA). This analysis is being done now because an EIS was not prepared prior to the contracts being offered.

The lack of an EIS was challenged by an environmental public interest group, Forelaws on Board. (See Appendix A, Forelaws on Board v. Johnson, 743 F.2d 677 [9th Cir., 1984].)

The U.S. Court of Appeals for the Ninth Circuit ordered that an EIS be prepared. The Court decision did not suspend operation of the contracts, but cited provisions of the contracts that allow for later amendment. The Court's opinion noted that all of the contracts contain a clause setting forth the procedures for amendment. Most important for NEPA purposes, the court noted that all of the contracts include language (General Contract Provisions, Section 45) by which the parties agree to negotiate amendments as necessary to allow the Northwest Power Planning Council's (Council) Conservation and Electric Power Plan and Fish and Wildlife Program to be effective.

This Final EIS takes into account the unusual circumstance that the contracts have been in effect for several years and were left in effect by the Court Order. Therefore, this EIS looks at the effects of the existing contracts and potential amendments today, rather than looking back at the circumstances of 1981, when the contracts were offered. The Power Sales Contracts may affect the environment to the extent that they require BPA or customers to take certain actions or to operate the power system in specific ways. Contractual requirements will be described for each alternative.

1.2 Need

BPA needs an evaluation of the currently-effective Northwest Power Act Firm Power Sales Contracts and Residential Purchase and Sale Agreements to help determine whether they should be preserved or changed.

1.3 Purposes

The purposes of this midterm evaluation are specifically related to points of interest expressed by the Court, as well as to BPA's statutory obligations to its customers. These purposes are:

- To support continuing consideration of the Northwest Power Act's priorities, and the Council's Conservation and Electric Power Plan and Fish and Wildlife Program with respect to resource decisions made by BPA.

- To appropriately incorporate into BPA's obligations as a power supplier its duties to protect, mitigate, and enhance fish and wildlife, and to be consistent with the provisions of the Council's Fish and Wildlife Program.

- To continue to provide BPA customers with the firm power sales and residential exchange contract rights to which they are entitled under the Northwest Power Act and other applicable statutes in a manner consistent with BPA's other statutory mandates and prudent utility practice.

- To support acceptable environmental quality and achieve consistency with other national policies.

It should be noted that BPA's purposes cannot necessarily be achieved by unilateral action or regulation. As a power marketing agency dealing with independent utilities and companies, BPA must generally negotiate with its customers to balance BPA's purposes with the needs and desires of other entities. This requires a weighting of environmental, economic, and other public policy considerations. The efficacy of alternatives will be assessed in light of BPA's multiple purposes, while considering the autonomy of BPA's customers.

1.4 History of the Northwest Power Act Power Sales Contracts

Electric power planning in the Pacific Northwest faced a number of challenges which eventually culminated in the enactment of the Northwest Power Act in December 1980. The subject Power Sales Contracts were intended to play a specific role in a regional scheme. Understanding this role and this scheme will aid understanding of these contracts.

1.4.1 Conditions Prior to the Northwest Power Act

The Pacific Northwest System and BPA's relationships with its customers prior to the Northwest Power Act are thoroughly described in the Draft EIS on the Role of The Bonneville Power Administration in the Pacific Northwest Power Supply System (July 1977), also known as the Draft Role EIS, and in this Final EIS, especially in Appendices A and C. A brief synopsis of relevant events is provided here.

Prior to passage of the Northwest Power Act, BPA had Power Sales Contracts for many years with the customers who signed the Northwest Power Act contracts in 1981. Utilities that were public bodies or cooperatives were BPA's preference customers. BPA also sold firm power to investor-owned utilities (IOU's), some direct-service industries (DSIs) and some Federal agencies.

When it appeared that Pacific Northwest loads would exceed the amount of power BPA had available to market, this insufficiency was addressed at first by a regionwide voluntary effort by BPA and its customers to act as a group in planning, financing, and integrating new generating resources to serve load growth. All these parties had then, as they have now, a common interest in maximizing the benefits of the Federal Columbia River Power System (FCRPS), for which BPA is the power marketing agency. Each of BPA's customer groups could, in different ways, benefit from the FCRPS power and the flexible planning and operating capabilities of the system.

This regional effort was known as the Hydro-Thermal Power Program. The Hydro-Thermal Power Program attempted to deal with BPA's insufficiency with a plan in which Northwest IOU and public agency utilities would share with BPA the task of providing a thermal base load generation in the region to serve load growth. The so-called "one-utility" concept was essential to this plan. The one-utility concept meant that electric power planning in the Pacific Northwest would approximate, as closely as possible, the planning of a system under one owner. Costly redundancies which might occur if each utility developed transmission and generating resources for its own service area would thereby be avoided. For a variety of reasons, the Hydro-Thermal Power Program could not be fully implemented, although some resources were built or begun. BPA issued a notice of insufficiency to IOU's in 1971, and to preference customers in 1976. For a more detailed description, see the Draft Role EIS, Part 1, pages II-7 through II-17.

1.4.2 Effect of the Northwest Power Act on Relationships Among BPA and Its Customers

After the Hydro-Thermal Power Program, the Pacific Northwest turned to national legislation to create a mechanism for serving Pacific Northwest power needs. On December 5, 1980, Public Law 96-501, the Northwest Power Act, was signed into law. The Northwest Power Act assumed that BPA, the Council, and BPA's customer groups would have interdependent roles, although only BPA and the Council were required to perform their respective roles. The Power Sales Contracts were essential to this concept of interdependent roles.

BPA was to purchase generating capacity of future resource additions and integrate them into the Federal power system. Pursuant to the generic Utility Power Sales Contracts, BPA would serve the load growth of its utility customers to the extent each utility did not serve its own load if they so requested. Utilities were to develop resources and sell them to BPA. Customers were to pay for the total costs of service through rates tailored to customer groups. By means of the residential exchange agreements, BPA would provide a financial benefit to reduce the underlying costs of the residential and small farm rates of IOU's and public agencies. The near-term costs of this would be paid by DSIs. Under the DSI Power Sales Contracts, DSIs would receive a new long-term power supply certainty for the amount of power provided under their previous contracts and would provide BPA with reserves through interruptibility. BPA was prohibited from selling power to new DSIs, and the amounts of power sold to existing DSIs was not permitted to increase BPA's net obligation (except for technological allowances) unless specified findings were made regarding need for reserves.

Much negotiation between the parties to the contracts resulted from disagreements regarding their specific obligations under these roles; the appropriate balances of costs and benefits; and the policy objectives of the Northwest Power Act. Other areas of negotiation centered around past occurrences which had not been satisfactorily resolved--DSI interruptibility, and allocations to preference customers in event of insufficiency, for example. Thus, these Power Sales Contracts were shaped by both past events and new policies.

1.4.3 Changed Conditions Affecting the Northwest Power Act Scheme

The Northwest Power Act was designed around an assumption that there would be a large need for future resources and that BPA could be the supplier of choice. Likewise, the Power Sales Contracts adopted this scenario and were primarily drafted to deal with a situation in which customer demand exceeds or keeps pace with BPA's supply.

The statutory provision that BPA offer requirements contracts to all utilities created a long-term supply obligation on BPA at the same time that BPA was granted authority to acquire resources. BPA was given resource priorities, with conservation being first priority. Utilities could then use BPA as a financial backer and load factoring agent for new resources, when needed.

BPA and other regional entities had firm power surpluses through the 1980's and have not been acquiring resources until recently. Thus, the region has not enjoyed the financing and shaping benefits a sale and repurchase contract mechanism was intended to provide. BPA's role as a supplier of resources to the entire Pacific Northwest has not yet developed. Most IOU's now project to purchase nothing from BPA under the Power Sales Contracts, but might buy under separate contracts with other utilities during the contractual 7-year planning horizon. Other utility customers have also indicated that they are seeking supply options other than from BPA.

It is also worth noting that the underlying concept of regional one-utility planning and regional cost sharing is not consistent with some current public utility regulatory principles nor with some ratepayer interest group positions. Increasingly, utility investments and commitments must be justified in terms of least cost to each utility's ratepayers only. Also, some Pacific Northwest utilities have come to associate the one-utility concept with an authoritarian scenario that cannot address their individual needs. The Council noted in its 1988 update of the 1986 Plan that there is little evidence to date that the region is moving toward a coordinated resource development path.

1.5 The NEPA Process for This EIS

BPA negotiated generic contract provisions which employed these general frameworks and other necessary provisions for utility customers (preference customers, IOU's, and Federal agencies), DSIs, and residential exchange customers. BPA offered these contracts to its customers on September 8, 1981, providing almost 1 year for acceptance of the offered contracts. The contracts were amended pursuant to settlement of lawsuits (Public Power Council v. Johnson, Pacific Power and Light v. Johnson, and Alcoa v. BPA, Ninth Court of Appeals Action No. 81-7806, 81-7803, and 81-7813, respectively), and these amendments were added to the offers, to be accepted no later than August 28, 1982.

BPA published a Final Environmental Report in September 1981, to accompany the initial contract offer, but did not prepare an Environmental Assessment (EA) or an EIS. BPA published an EA on the settlement amendments in July 1982. Late in 1981, the environmental group, Forelaws on Board, charged that BPA's failure to prepare an EIS on the initial contract offer violated NEPA. BPA argued that the deadlines imposed by the Northwest Power Act did not allow enough time for an EIS. In its September 1984 opinion, the United States Court of Appeals for the Ninth Circuit rejected BPA's argument and ordered that an EIS be prepared. The court held that the Environmental Report was a "document not contemplated by NEPA," and "did not analyze in detail any possible adverse environmental consequences of the contracts and ways that [the consequences] might be avoided." Forelaws on Board v. Johnson, 743 F.2d 677, 681. The court did not order BPA to stop operating under the contracts, but noted that all the contracts allow for amendment. "[T]he contracts are not completed projects for which an EIS will no longer be useful," the opinion stated. "Rather, they are agreements with the flexibility to accommodate the ongoing, changing relationship among BPA, its customers, and the public interest represented by the Regional Council...." 743 F.2d at 686.

A Federal Register Notice of Intent to prepare an EIS on the Long-Term Power Sales Contracts was published on March 5, 1985. At the same time, BPA sent 2,500 notices to Federal, State, and local agencies; BPA customers; the Council; interest groups; and others. Comments on the Notice of Intent were received from 16 parties.

On September 19, 1985, BPA sent a notice announcing scoping meetings and soliciting public comment. The five scoping meetings were held in October 1985, in Seattle and Richland, Washington; Portland, Oregon; Burley, Idaho; and Missoula, Montana. By the end of this phase of the scoping process, BPA had received 60 comment letters and 68 persons attended the scoping meetings. A summary of the comments received from March 5 to November 1, 1985, was assembled and distributed to the public for review and comment. This "cross-comment" period, from December 15, 1985, to January 31, 1986, allowed respondents to judge other comments and to reevaluate their own comments. One additional public meeting was held during this period to facilitate the cross-comment process. Fifteen additional comment letters were received.

In May 1987, BPA convened a Power Sales Contracts EIS Review Panel consisting of representatives from interested groups. Pacific Northwest utilities, DSIs, the Council, fishery and public interest representatives are included. The Review Panel functions as a sounding board for issues in the EIS. The Review Panel commented on BPA's drafts of an Implementation Plan for the EIS. The Panel also reviewed an analytical study plan and participated in technical review of interim drafts prior to the general distribution of the Draft EIS.

This EIS analyzes impacts of both the preferred alternative and other alternatives identified, so that the results may serve as a guide to future actions. As the Court's Order stated, this EIS may be used in connection with consideration of any further amendments to which NEPA also will apply.

The Court's order mentions that the results of this EIS may lead to consideration of later amendments which are themselves subject to NEPA and may require separate EIS's. BPA will follow a two-stage process. Stage one is the completion of this EIS with a decision document that would either ratify the existing contracts or commit BPA to search for new approaches if the results show cause for concern. Stage two encompasses an analysis of mechanisms to address such concerns. Assuming BPA's final decision is to take the action defined by the preferred alternative, the stage two process will be the development of a policy to enforce the Protected Areas Rule in BPA's resource-related transactions. The appropriate NEPA documentation for this policy will be prepared and it is expected to rely on previous analyses of Protected Areas provisions.

1.6 Relationship to Other Actions

Issues similar to those analyzed here arise in other separate proceedings.

1.6.1 BPA Resource Program and EIS

BPA's Resource Program (referred to in previous years as "Resource Strategy") is undergoing evaluation through a separate EIS process. This EIS is being prepared to display the environmental impacts of several different resource types to provide the necessary information for BPA to acquire future resources in an environmentally sound manner. Actions to be evaluated include planning for load growth with coal, conservation, nuclear, cogeneration, renewable resources such as hydropower, solar, and wind, combustion turbines, fuel switching from electricity to gas, and imports from Canada and California. The Resource Program EIS will quantify the costs of environmental impacts of potential resource acquisitions, and include those costs when determining resource cost-effectiveness. The EIS is significant because it will for the first time integrate environmental costs for all resource types into a single planning effort, influencing resource decisions for many years to come.

Specific resource decisions related to resource acquisitions will be covered by separate processes, such as the decision to finish or terminate Washington Public Power Supply System plants WNP-1 and -3.

1.6.2 System Operation Review (SOR) and EIS, and 1992 Salmon Flow Measures EIS

BPA, the U.S. Army Corps of Engineers (Corps), and the Bureau of Reclamation (BOR) are jointly conducting the Columbia River SOR, a comprehensive evaluation of management of the Columbia River. The impetus for the SOR is the expiration within the next decade of the agreements that coordinate hydropower generation on the Columbia, the Pacific Northwest Coordination Agreement and the Canadian Entitlement Allocation Agreements. In the years since those agreements were signed, demands on the river system have increased dramatically, with nonpower uses increasing significantly in importance. New operating agreements must consider the diverse and competing uses of the river system, which include power generation, flood control, navigation, recreation, and fish and wildlife. The SOR will cover broad issues related to balanced use of Federal multipurpose hydro facilities in the Columbia River Basin through a comprehensive public process on balancing the multiple uses of these facilities. The SOR process could lead to decisions affecting regional hydropower capability or operating flexibility.

The SOR scoping process involved national, regional, State, and local agencies and organizations and the general public. In addition, the SOR schedule was adjusted to allow incorporation of results of the "Salmon Summit" (the regional effort to develop consensus on measures to improve the survival of salmon species proposed for listing as threatened or endangered species) in the SOR's proposed alternatives for analysis. Such involvement of a broad range of interests will continue through preparation of the EIS associated with the SOR process.

The results of the analyses in the Northwest Power Act Power Sales Contracts EIS will have implications for the power sales contracts BPA offered in 1981. This EIS analyzes a broad range of alternatives in order to bracket the effects that could occur from retaining the power sales contracts as they are or changing them. In its contracts, BPA incorporates to the extent possible the use of the operational flexibility of the FCRPS to meet the needs of customers. However, contract language alone does not determine system operations, which must consider nonpower constraints on the system as well. Operational decisions such as those implicit in the Power Sales Contracts will be made after consideration of the analyses and agreements that are part of or result from the SOR EIS and may reduce the flexibility available on the system to accommodate customer needs.

A closely related effort is the 1992 Columbia River Salmon Flow Measures EIS and Options Analysis, which is under preparation by the Corps. This EIS will address adjustments in Snake River flows to enhance the survival of salmon species proposed by the National Marine Fisheries Service for listing as threatened or endangered species.

1.6.3 Proposed Listings of Snake River Salmon Runs as Threatened or Endangered Species under the Endangered Species Act

The National Marine Fisheries Service (NMFS) has proposed listing three species of Snake River salmon as threatened or endangered species under the Endangered Species Act. These species are Snake River sockeye salmon, Snake River spring and summer chinook (as a single species), and Snake River fall chinook. Since the proposed listings were announced, BPA has begun to confer with NMFS to evaluate the effect of BPA's activities on the runs proposed for listing.

The focus of discussions with NMFS has been the operation of the hydro system. The power sales contracts, and other specific transactions, are not the subject of individual analysis in this process because individual transactions have limited effects on hydro operations, especially in how those operations may affect the species of concern. Individual transactions do not control the effect of the hydro system, because they are conducted within the scope of established operating constraints that are designed to balance power and non-power uses of the river. The most effective approach to deal with these effects is to address operations in a larger scope directly, rather than attempting to make piecemeal adjustments for each transaction. As is discussed above, operations on the hydro system are the subject of analysis in the System Operation Review and the 1992 Flow Measures EIS.

1.6.4 BPA Ratemaking

Decisions involving the exercise of BPA ratemaking authority will not be analyzed in this EIS. Assumptions will necessarily be included regarding projected BPA rates, but rate issues and alternatives will not be examined here. Such issues are analyzed in separate proceedings and in separate environmental evaluation processes.

1.6.5 DSI Options Study

Shortly after the start of BPA's 1985 rate case, the DSI Options Study was announced to look at various long-term options for improving DSI viability while generally benefiting the region. Five options available to BPA were examined:

(1) a variable rate for aluminum DSIs tied to the price of aluminum;
(2) a reduction in current rates in return for increased power interruptibility rights in the future;
(3) allowing the DSIs to purchase power from other suppliers who might provide more attractive rates than could be provided by BPA;
(4) financial support to encourage conservation and modernization investments in DSI plants; and
(5) no Action.

A DSI Options Study EIS was prepared. Based on the results of the study and public comment, BPA pursued two of the options, the variable rate option, and a conservation and modernization (Con/Mod) program. BPA also pursued a methodology to link the IP (industrial firm power) rate for DSIs and the PF (preference customer) rate for preference customers, as provided by the Northwest Power Act, section 7(c)(2). The variable rate and the Con/Mod program were implemented by separate contracts. The variable rate contract provides a temporary option to the generic DSI Power Sales Contract with respect to rate and quality of service provisions for the aluminum smelters, all of which have elected to sign that contract. BPA has submitted for approval by the Federal Energy Regulatory Commission (FERC) an extension of the variable rate from July 1, 1993, through June 30, 1996, to complete the 10-year period originally planned during which the rate would be available.

DSI issues covered in the DSI Options EIS will not be studied in this EIS. The actions that were taken following that EIS are included as part of the base case, and also in the alternatives, except for those alternatives which are inconsistent with the assumed continuation of those actions. Due to interest expressed during scoping for this EIS, the environmental impacts of the option concerning increased DSI interruptibility, which was not studied in the DSI Options EIS because of its lack of economic benefits, is analyzed here.

1.6.6 Other Marketing and Services

BPA engages in marketing and provides services under many contracts other than the Power Sales Contracts analyzed here. These sales and services are provided by BPA for purposes other than those overall purposes described in sections 5(b), (c), (d), and (g) of the Northwest Power Act. Other BPA marketing and service activities which will not be included in this EIS because they are undertaken under other authorities include the following: sales of surplus firm power both in and out of region; firm displacement sales; capacity contracts; storage and other operational agreements; and exchange agreements. It is possible that certain marketing options may raise environmental issues similar to those studied here. The appropriate NEPA documentation for such marketing activities will be determined when such proposals are made. BPA is in the process of developing a policy to govern marketing of surplus firm and nonfirm energy and will prepare a NEPA document to address the environmental impacts of the proposed policy.

1.6.7 Intertie Access Policy, Intertie Development and Use

BPA owns certain major transmission lines which interconnect the Pacific Northwest Federal system with other regions. These lines are referred to as Interties. Environmental issues related to the Pacific Northwest-Pacific Southwest Intertie are addressed in the Intertie Development and Use (IDU) EIS. This EIS will not duplicate analysis covered by the IDU EIS, but refers to that document for analysis of certain issues. BPA is also preparing an EIS on Non-Federal Participation in the Third AC Intertie, an addition to existing

Intertie facilities which will expand the capability of Northwest utilities to deliver power to the Pacific Southwest and provide Intertie access to additional parties.

Changes in amount of power available for export which are attributable to the Power Sales Contracts and the alternatives are noted in this EIS.

1.6.8 Average System Cost Methodology

Average system cost methodology is developed for the Residential Exchange Agreements in accordance with the consultation process specified in section 5(c)(7) of the Northwest Power Act. The methodology is detailed in the Administrator's Record of Decision, June 1984. Issues or questions regarding BPA's methodology will not be a subject of this EIS.

1.6.9 Northwest Power Planning Council's Plan and Fish and Wildlife Program

The Council has specifically requested that BPA explain in this EIS whether any provisions of the Power Sales Contracts impair the effectiveness of the Conservation and Electric Power Plan, or the Fish and Wildlife Program. This is done as alternatives are described. The Council has also requested that BPA evaluate mechanisms for increasing the transfer of conservation among the region's utilities and look at ways to enhance its role as power supplier to the region. These items are addressed in Alternatives 2.2 and 3.2, respectively.

1.6.10 Renegotiation of BPA Power Sales Contracts

BPA is planning the process for renegotiation of its utility and DSI power sales contracts and its residential purchase and sale agreements. Renegotiation will help to clarify resource obligations for BPA and its customers in the years after expiration of current contracts. The issues and alternatives in this EIS will contribute to the identification of issues and alternatives for the renegotiation effort. BPA will prepare an EIS on the new contracts, and will conduct a public involvement program to obtain the input of all interested parties.

CHAPTER 2

Alternatives Including The Proposed Action

CHAPTER 2

ALTERNATIVES INCLUDING THE PROPOSED ACTION

INTRODUCTION

This EIS will analyze two basic alternatives: (1) the No Action Alternative--in which BPA would preserve the Long-Term Power Sales Contracts without change, or (2) pursuit of modifications. To allow for clear comparisons, the second alternative is divided into five categories corresponding to major policy areas (see Figure II-1):

(1) Hydro Development and Operations
(2) Conservation (including renewable resources directly applied by end users)
(3) Resource Planning and Development
(4) Quality of Service as a Resource Choice
(5) Industrial Load Constraints

Each category of alternatives encompasses a range of possible changes. Most address separate concepts and therefore are not alternatives to each other. The No Action Alternative, consisting of existing contract provisions, will be described in relation to each specific alternative as that alternative is discussed. The No Action alternative is the Base Case for analysis.

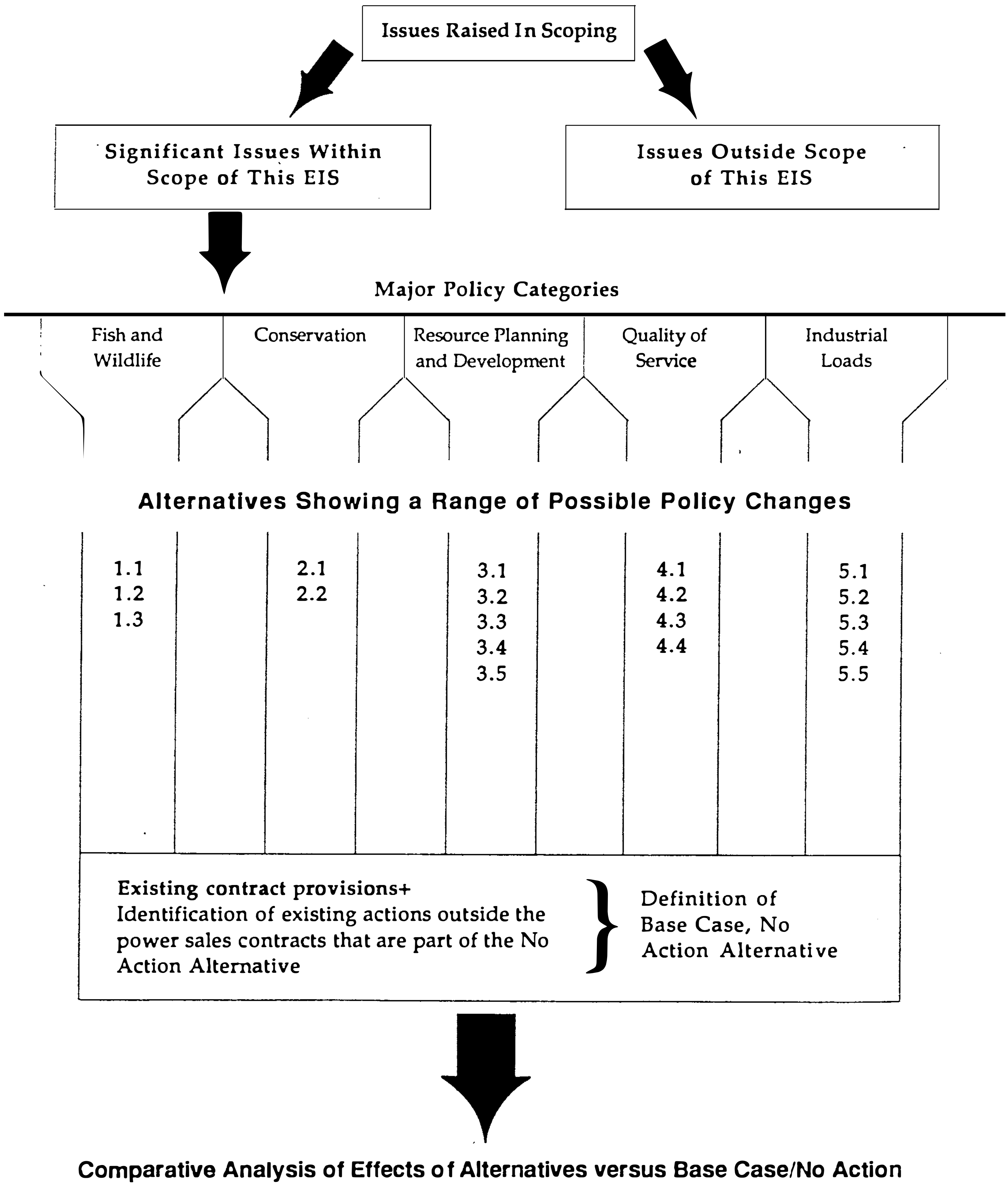
This EIS will not analyze combination "packages" of alternatives. It would be premature to assume or speculate upon potential compromises that might be required in negotiation to gain agreement on any modification of the contracts. After the completion of this EIS, any later activity to study specific proposals for change will take into account their impacts and costs as those may be identified or identifiable.

PROPOSED ACTION - PREFERRED ALTERNATIVE

BPA's proposed action and preferred alternative is the element of Alternative 1.1 which provides for the enforcement of the Northwest Power Planning Council's Protected Areas Rule on new hydro development. This is a change from the Draft EIS, in which the preferred alternative was the No Action Alternative, that is, continuation of the subject contracts without change. BPA plans to implement the preferred alternative through the development of a Protected Areas policy, rather than through amendment of the existing contracts or renegotiation of the contracts. BPA plans to begin the policy development process shortly after the completion of a Record of Decision on this Final EIS.

Figure II- 1

Long-Term Power Sales Contracts
Identification of Alternatives and Base Case



DETAILED DESCRIPTIONS OF ALTERNATIVES
CATEGORY 1: HYDRO DEVELOPMENT AND OPERATIONS ALTERNATIVES

This category of alternatives concerns ways in which the contracts could have effects on hydro resources and their operation and, therefore, on fish and wildlife, recreation, flood control, irrigation, and other uses of the FCRPS. Note that decisions regarding hydro system operations will be made after consideration of the analyses and agreements connected with the SOR EIS.

Overview of Hydro Development and Operations Issues

The operation of the FCRPS is primarily controlled by agreements and practices outside the Power Sales Contracts studied here. (See Appendix C.) In general, operations under these other agreements and practices use hydro facilities, within the limits of nonpower constraints, to the greatest degree possible to achieve overall economies of service for electric power consumers. Alternative strategies for system operation are the subject of analysis in the System Operation Review EIS (see Chapter 1, section 1.6.2).

Appendix C provides a guide to basic principles of the operation of the Pacific Northwest hydro power system. A key concept is that the FCRPS is a multiuse resource. The use of the FCRPS for power production is carried out in an environment of limitations and constraints for other purposes such as flood control, navigation, fishery benefits, recreation, and other uses.

It is important to understand that Pacific Northwest hydro operations and development are controlled and constrained by a variety of State and Federal laws and regulations, as well as contracts and operating practices. As Appendix C explains, the power uses of the hydro system have long been subordinated to operational constraints in favor of nonpower uses, such as fish and wildlife, flood control, irrigation, navigation, and recreation. In the years since the passage of the Northwest Power Act and the Electric Consumers Protection Act (ECPA), these constraints have increased, accompanied by pro-active fish and wildlife investments and programs.

For example, BPA investments for fish and wildlife increased from approximately $20 million a year prior to the Council's program, to more than $150 million a year currently. Program costs include direct expenditures for capital and expense items, as well as hydro operations for the benefit of fisheries. These hydro operations include the Water Budget (for which a volume of water is reserved for release to improve streamflows for downstream migration of juvenile salmon and steelhead) and spill plans (for which water is passed through a hydro project without generating electricity). Other items include fish bypass installations, hatcheries, operation and maintenance (O&M) expenses and interest on the Corps and BOR capital investments for fish and wildlife, and a variety of research projects. BPA has implemented most of the major elements of the Northwest Power Planning Council's 1987 Fish and Wildlife Program, including construction of major hatcheries for salmon, steelhead, and resident fish, trusts for wildlife mitigation, and numerous other wildlife activities. BPA's Intertie Access Policy contains provisions designed to inhibit development of hydro resources in areas covered by the Council's Protected Areas program. BPA's review process to develop policy on acquisition of resources also provides an opportunity to address these issues. All of these activities and expenditures result in a high level of fish and wildlife benefit which exists in the No Action Alternative.

Alternative 1.1 Fish and Wildlife Compliance As A Condition of Service

1.1.1 Description of Alternative. This alternative assumes that the utility and DSI Power Sales Contracts and residential exchange agreements are modified to require utilities to implement the Council's Fish and Wildlife Program. This issue was raised during initial contract negotiations in comment language proposed by the National Marine Fisheries Service (NMFS) to be added to the Utility Power Sales Contracts. This proposed contract provision would have required the parties to implement "necessary measures" to protect, mitigate, and enhance fish and wildlife. This proposed provision was as follows:

> In carrying out the obligations under this contract, the parties also agree to implement measures necessary for the protection, mitigation, and enhancement of fish and wildlife resources, particularly anadromous fish and their habitat. Necessary measures are those which are established: (1) in a license or order issued by the Federal Energy Regulatory Commission; (2) in the section 4 power plan, where the section 4(h) fisheries program established under the Pacific Northwest Electric Power Planning and Conservation Act; or (3) by the Administrator, upon recommendation of a state or Federal fish and wildlife agency or Indian tribe, in order to satisfy his obligations to protect, mitigate, and enhance the fish and wildlife under the Pacific Northwest Electric Power Planning and Conservation Act. Nothing in this contract shall be interpreted to prevent or impair the implementation of measures for the protection, mitigation, and enhancement of fish and wildlife resources, . . .

The alternative studied here is not identical to the NMFS provision in that Alternative 1.1 does not include a change in BPA's obligation nor an extension of the utility obligation to "necessary measures" beyond FERC requirements or provisions of the Council's Fish and Wildlife Program. The alternative has been simplified for this EIS in order to focus on the major policy issue without diverging into interpretation of the specific language proposed by NMFS. We do not analyze a change in BPA's fish and wildlife obligations here because that issue is much broader than the Power Sales Contracts and is based on interpretation of the Northwest Power Act.

Though the NMFS proposal could theoretically include measures beyond the Council's Fish and Wildlife Program, we have no practical basis on which to identify these measures. The EIS analysis assumes no changes or additions to the Council's Program other than those presently adopted by the Council. We will assume no changes to FERC license conditions beyond those specified in the Fish and Wildlife Program. The alternative is assumed to have no effect on Fish and Wildlife Program compliance by Federal project owners and operators, including BPA, whose fish and wildlife responsibilities are set by statute.

Note that additional requirements for utilities to implement the Council's Fish and Wildlife Program likely would be accompanied, through the negotiation process, by additional compensation to utilities for these obligations or additional means by which utilities could participate in and influence the formulation of the Program.

In response to proposals by the National Marine Fisheries Service (NMFS) to list three species of Snake River salmon as threatened or endangered species under the Endangered Species Act, fish and wildlife agencies and other interested groups are working with project operators to develop measures to enhance the survival of species proposed for listing. BPA and NMFS have begun to confer under ESA to evaluate the effect of these species on operations which support BPA's power marketing. In addition, the Northwest Power Planning Council is considering amendments to its Fish and Wildlife Program to address the proposed listings. These efforts are expected to lead to changes in hydro operations and in other activities designed to increase the numbers of salmon in the Columbia River system. These changes do not directly affect the analysis of this alternative; for utilities affected by the proposed listings, compliance with the Council's Fish and Wildlife Program would tend to increase independent of the effect of a power sales contract provisions requiring compliance.

1.1.2 No Action Alternative. Under the existing contracts, utilities affirm their legal obligations related to fish and wildlife which may be established by FERC. (Utility Power Sales Contract, section 6.) Utilities provide fish and wildlife protection independent of the Council's Fish and Wildlife Program by complying with these legal obligations.

The Northwest Power Act imposed obligations for fish and wildlife but did not directly extend such obligations to utilities. During Power Sales Contract negotiations in 1980-1981, utilities were not willing to commit to implementation of the as-yet-unformulated Fish and Wildlife Program, or other "necessary measures." BPA proposed the NMFS language to the other negotiating parties, but it was strongly opposed as a "blank check" that would have exposed utilities to unknown costs. Without such a contract provision, enforcement of compliance with fish and wildlife measures relies upon obligations other than the power sales contract and depends upon the exercise of authority by existing agencies with duties related to the hydro system or to fish and wildlife. Compliance with the Fish and Wildlife Program can be achieved through FERC direct authority over hydro project licenses. BPA and the Council influence utilities by means of policies such as the Council's Protected Areas rule, BPA's Intertie Access Policy, and intervention in appropriate proceedings before FERC. BPA's utility customers support the Council's Fish and Wildlife Program through their power purchases, which contribute to the revenues from which the Program is financed.

Operation of the Pacific Northwest hydro system is primarily controlled by agreements and practices outside the contracts studied here. (See Appendix C.) The following sections explain how the Power Sales Contracts address hydro operations and development and fish and wildlife.

1.1.2.1. Contract Provisions Which Address Hydro Development and Operation

A provision addressing general fish and wildlife policy is found in BPA's General Contract Provisions (also see Appendix B), which are attached to each of the three types of Northwest Power Act Power Sales Contracts (Utility Power Sales; DSI Power Sales; and Residential Exchange Agreement). General Contract Provision 45, Cooperation with Regional Council, reads as follows:

> The parties will negotiate amendments to this contract as may be necessary to permit the plan or program adopted by the Pacific Northwest Electric Power and Conservation Planning Council pursuant to P.L. 96-501, including but not limited to provisions pertaining to conservation, renewable resources, and fish and wildlife, to be effective in the manner and for the purposes set forth in Sections 4 and 5 of P.L. 96-501.

Section 6, Interpretation of Fish and Wildlife Responsibilities, in BPA's generic Utility Power Sales Contracts, contains the following:

> In meeting its obligations under this contract, Bonneville affirms its obligations under Section 4 and 6 of P.L. 96-501 and other applicable laws with respect to implementation of measures and objectives for the protection, mitigation, and enhancement of fish and wildlife, while assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply. This contract shall not impair compliance with such obligations.
>
> The purchaser affirms its legal obligations related to fish and wildlife established in any license or order issued by the Federal Energy Regulatory Commission. This contract shall not expand, impair, or in any way alter the purchaser's legal obligations related to fish and wildlife established in a license or order issued by the Federal Energy Regulatory Commission.

The utility contract also imposes limitations on a purchaser's rights to shape the monthly energy capability of its Firm Resources differently from its monthly Firm Energy Load, i.e., limits on shifting and borrowing of the purchaser's Firm Energy Load Carrying Capability (FELCC). FELCC is the minimum level of energy that can be produced and shaped to load during the period it would take reservoirs to be drafted from full to empty under critical streamflow conditions. FELCC shifting and borrowing are described in greater detail in Appendix C. There are two contract provisions which limit the extent to which a Computed Requirements purchaser can shift its FELCC among years in the multiple-year critical period (shifting), and among months in each year (borrowing). The pertinent sections are 16(c)(1) and 16(c)(2), respectively.

The first paragraph of section 16(b) also refers to the limitations in sections 16(c)(1) and 16(c)(2). Since the term "Seasonal Storage" is defined in the contract to include access to reservoir storage through firm contracts, all of the purchasers who are parties to the Pacific Northwest Coordination Agreement are subject to these limitations. However, these limitations are meaningless for Utility Power Sales Contract parties which do not purchase from BPA, because the provisions only limit the shape of the load the purchaser puts on BPA.

Under the Utility Power Sales Contracts that preceded those offered under the Northwest Power Act, it was BPA's policy to impose these limits on shifting FELCC among years of the multiyear planning period (critical period) and among months of an operating year. The language in the existing contracts formalizes that policy. The limitations reasonably divide the responsibility for meeting the utility's total load between the purchaser's resources and BPA's. Absence of the shifting limit would have allowed purchasers to purchase relatively small amounts of firm power from BPA when resources from the first year of the critical period were adopted, then to purchase relatively large amounts on the rare occasions when other than the first year was adopted due to failure to refill reservoirs. Absence of the monthly shaping limit would have allowed purchasers to purchase relatively small amounts of firm power during months when power was likely to be surplus (e.g., May) and relatively large amounts when power was likely to be in short supply.

If these limitations were not included in the contract, BPA's Computed Requirements purchasers (for definition, see Glossary or Appendix B, section B.4.) could participate in shifting and borrowing of FELCC each year at the time the Coordination Agreement operations planning is done. This might have some effect of increasing the planned generation at the purchasers' resources during the first year of the critical period during times when the coordinated system has a net surplus over the critical period and shifting of FELCC surplus among years is allowed. (See Appendix C, Section 3 on "Borrowing Techniques.") More likely, it would leave the planned generation virtually unchanged and increase the planned interchange energy transfers from BPA to the purchasers.

1.1.2.2. Contract Provisions Which Support Implementation of Fish and Wildlife Measures

There is a "flip side" to the question of whether the contracts contain sufficient positive provisions to protect fish and wildlife. Is a purchaser hampered by the contract from operating its Firm Resources to meet nonpower objectives, such as fish and wildlife? Fish and wildlife agencies had complained that BPA customers would argue that their pre-Act BPA contract obligations prevented them from performing operations in favor of fish by prescribing the operation of the utilities' resources.

Besides the general policy support in section 6 and GCP 45 discussed under question 1, the current contract provisions endeavor to end this problem with respect to specific procedures. There are three specific areas to examine: (a) To what extent is a purchaser allowed under the contract to remove a Firm Resource in order to accomplish some nonpower objective? (b) To what extent is a purchaser which has not removed a Firm Resource allowed under the contract to limit the Assured Capability of that resource in order to be able to meet some nonpower objective? (c) To what extent is a purchaser which has not removed a Firm Resource or limited its Assured Capability allowed under the contract to reduce operations of that resource in order to meet some nonpower objective? We conclude that the contract does not hamper any customer from meeting nonpower objectives, such as fish and wildlife measures. Detailed explanation follows.

(a) To what extent is a purchaser allowed under the contract to remove a Firm Resource in order to accomplish some nonpower objective?

The answer to this question is controlled mainly by the provisions of section 12 of the generic Utility Power Sales Contract. Basically, this section provides that each purchaser will prepare, at the outset of the contract, an exhibit listing each of the purchaser's Firm Resources. (See example Firm Resource Exhibit, Appendix B, Table B-1.) Thereafter, the purchaser may, by submitting a revised Firm Resource Exhibit by January 1 of any year, remove Firm Resources from its Firm Resource exhibit, without any restriction, on 7 years' notice for energy capability and 5 years' notice for peak capability [12(b)(8)]. In addition, the purchaser may remove Firm Resources:

(1) to the extent that BPA has a surplus of Firm Resources [12(b)(9)];

(2) to the extent the purchaser adds another equivalent Firm Resource [12(b)(10)];

(3) if the use of the resource is permanently discontinued because of loss of resource resulting from factors beyond the control of the purchaser [12(b)(8)];

(4) if the use of a resource is permanently discontinued because of obsolescence or retirement and BPA has agreed in writing [12(b)(8)]; or

(5) if BPA has given prior written consent [12(b)(14)].

So, if a purchaser wishes to stop using one of its firm resources because of an environmental restriction or to avoid adverse fish and wildlife impacts, and wishes to replace that resource with a BPA firm purchase, it is assured of being able to do so within not more than 7 years. Paragraph 12(b)(9) was applicable from the effective date of the contracts until Operating Year 1991 because BPA had a firm energy surplus.

(b) To what extent is a purchaser that has not removed a Firm Resource allowed under the contract to limit the Assured Capability of that resource in order to be able to meet some nonpower objective?

The answer to this question is controlled by the provisions of section 16. If the purchaser's Firm Resources are covered by the Pacific Northwest Coordination Agreement, then Assured Capability is determined for those resources in accordance with that agreement. If not, Assured Capabilities are determined under section 16(b)(2) of the Power Sales Contract which attempts to duplicate the methods of the Coordination Agreement as closely as practicable. In either case, the Assured Capability of the purchaser's Firm Resources will be determined from studies made between February 1 and July 1 of each year. (See example Assured Capability Exhibit, Appendix B, Table B-2.) These studies reflect operating constraints, including nonpower constraints, submitted by resource owners prior to February 1 of each year. Section 16(d) of the Power Sales Contract specifically addresses the submission of operating constraints by owners of resources, and specifically recognizes recreation and fish and wildlife as potential operating constraints. Thus, the customer may reduce the Assured Capability of any of its Firm Resources by submitting appropriate operating constraints prior to February 1 of each year. These new constraints will normally be reflected in reduced Assured Capabilities beginning on the following July 1. If Assured Capabilities turn out to be based on other than the first year of a multiple-year critical period, reductions in Assured Capability will depend on adjustments to studies prepared in prior years, which may or may not be possible.

(c) To what extent is a purchaser that has not removed a Firm Resource or limited its Assured Capability allowed under the contract to reduce operations of that resource in order to meet some nonpower objective?

Several contract sections must be consulted to answer this question. It will be seen that, in this case, the purchaser may make the desired changes in operations, but would not have a right to obligate BPA to serve the load as a required load. The purchaser would bear the cost directly.

In general, a purchaser's right to purchase firm power from BPA is equal to its firm load less the Assured Capability of its Firm Resources (section 17). Since a decision by a purchaser after February 1 to operate a resource in such a way that its capability is reduced would not reduce that purchaser's Assured Capability, that purchaser would not have a corresponding increased right to purchase additional firm power from BPA for the reduction. The effect of the Power Sales Contract working together with the Pacific Northwest Coordination Agreement would be to leave the purchaser without an assured additional purchase of firm power under its BPA contract. However, unless absolutely no replacement power supplies were available at any price, the purchaser may acquire from other sources. The effect on the purchaser would be a cost equal to the difference between the cost of replacement power and the cost of the firm resource which is reduced.

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The above discussions have concentrated on whether the purchaser would, under the Power Sales Contract, have a firm right to obtain from BPA the power capability lost due to the nonpower operation. In the cases described by questions a and b, the purchaser did, and in the case of question c, the purchaser did not have that firm right. Thus, in the conditions described in questions a and b, BPA would have to provide a replacement power supply, while in the condition in question c, the purchaser would have to do so. If the required notice is given, BPA is obligated to provide replacement resources.

Most commonly, the real problem is not the purchaser's ability to obtain a replacement firm power supply, but the cost to the purchaser of replacing the power foregone. Such costs may result from having to purchase a quantity of nonfirm power, if any is available from BPA or other sources at the time. Or costs may come from making increased purchases of firm power from BPA if nonfirm power is not available. The purchaser also may have to give up marketing a quantity of nonfirm power equal to the generation foregone to accommodate the nonpower operation.

In summary, if the purchaser can use the provisions of sections 12(b) or 16(d) to increase its right to purchase additional firm power from BPA, the Power Sales Contract enhances the purchaser's ability to effect a nonpower operation. If the consequence is for the purchaser to forego a nonfirm sale or to have to purchase firm or nonfirm replacement power when such power is available, the Power Sales Contract is not a constraint of the purchaser's ability to effect a nonpower operation. In the case where replacement power is not available and there is insufficient lead time for the purchaser to place the additional firm load on BPA, the purchaser may perform the operation, but at its own cost. In most cases, the decision to effect the nonpower operation depends on the cost to the purchaser of sales foregone or of purchasing replacement power.

If the purchaser could reduce its assured resources by the amount of power foregone without notice to BPA, even at times when power supplies are critically short, this would place all the responsibility and cost on BPA for replacing the lost power supply. The purchaser would pay the cost of the replacement power at the BPA Priority Firm Power rate, which might be less than BPA's cost of replacement power. As a result, BPA could have to raise its rates to recover the cost of the replacement power purchased or the resource acquired.

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Aside from these three basic questions, there has been concern as to the effects of the obligation under the Utility Power Sales Contracts that a purchaser must be prepared to operate its Firm Resources to produce their claimed peaking capabilities (called the 6-hour limitation). This seems to be a widely misunderstood issue. Therefore, some general explanation is in order.

Under the Utility Power Sales Contracts, each Computed Requirements purchaser prepares and submits to BPA an exhibit setting forth the purchaser's Assured Energy Capability and Assured Peak Capability, by month, for the current contract year. Then, each month, that purchaser has a right to take from BPA firm energy equal to the excess of the purchaser's Actual Energy Load over its Assured Energy Capability, and has a right to take that energy from BPA at hourly rates up to the excess of the purchaser's Actual Peak Load over its Assured Peak Capability (higher rates of delivery are permitted during nighttime and weekend light-load hours). Planned Computed Requirements and Contracted Requirements purchasers are treated somewhat differently with respect to computing the amount of firm power they have a right to take from BPA. The 6-hour limitation applies to them as well, however. Also, an Actual Computed Requirements purchaser may modify its Assured Energy Capability, within limits, using its "Flexibility Account," a detail not necessary for an understanding of the 6-hour peak limitation section 17(g)(1).

The essential point is that some Computed Requirements purchasers have so much Assured Peak Capability compared to their Assured Energy Capability, Firm Energy Load, and Firm Peak Load, that their energy requirement is higher than their peak requirement. Section 17(g)(1) says that, under these circumstances, the purchaser may take energy from BPA at rates up to its energy requirement during heavy (peak) load hours even though that rate exceeds its Computed Peak Requirement and, presumably, its need to take power during those hours. Section 17(g)(1) goes on to say that, under some circumstances that are spelled out in detail, BPA may limit the rate at which the purchaser takes energy to its computed peak requirement for up to 6 hours during each day.

The contract provision as it stands represents a compromise. First, the conditions under which BPA may limit deliveries to the purchaser's Peak Computed Requirement are severely limited by the language of 17(g)(1), which states:

> BPA shall not so limit the amounts of power it makes available unless: (A) Bonneville has informed the Purchaser's representative by the time specified in the Power Scheduling Provisions Exhibit that Bonneville will make such limitation; (B) Bonneville has limited all other Customers having contracts which permit this limitation approximately in proportion to the amount by which each such Customer's Computed Average Energy Requirement exceeds its Computed Peak Requirement for such month; and (C) Bonneville has determined that such limitation is reasonably necessary either (1) to enable Bonneville to meet loads which Bonneville serves from firm load carrying capability as defined in the Coordination Agreement or (2) to serve other loads in the Pacific Northwest which Bonneville has previously committed to serve provided that the Purchaser, using its best efforts, is able to comply with such request on an operating basis.

Second, the language of section 16(d) indicates that a purchaser may limit the claimed peak capabilities of its Firm Resources by submitting operating constraints, including nonpower operating constraints needed to meet recreation and fish and wildlife obligations, at the outset of any annual planning process.

If the limitations of 17(g)(1) were eliminated from the contract, the region would be exposed to the need for duplicate firm peak resources.

Alternative 1.2 No Use of Borrowing Techniques for DSI First Quartile Service

1.2.1 Description of Alternative. As explained in Appendix B, Guide to Northwest Power Act Contracts, DSI load is divided into four quartiles, of which three are considered firm load for which BPA must plan resources. For this alternative, it is assumed that use of the hydro operations borrowing mechanisms of FELCC Shift, Advance Energy, or Flexibility Energy are not included in the DSI Power Sales Contracts to provide service to the DSI First Quartile, and that such operations would not be used for this purpose. The terms FELCC Shift, Advance Energy, and Flexibility Energy are operational planning terms that refer to different mechanisms which can change the timing of drafts of water from reservoirs. Readers unfamiliar with these terms should consult Appendix C, Guide to Hydro Operations In the Pacific Northwest Coordinated System. These mechanisms raise environmental concerns because they result in changed reservoir levels and flows.

Other than changing service mechanisms to the First Quartile, all assumptions will be the same as in the Base Case, including the assumption that all parties to the Coordination Agreement operate to use FELCC shift, Advance Energy, and Flexibility to the full extent that the Coordination Agreement and their contracts allow. For purposes of analysis, we will assume the DSI First Quartile will be served from other sources in this order: nonfirm energy, surplus firm energy, or purchases when resources are available at reasonable cost.

1.2.2 No Action Alternative. Appendix C contains a description of operational mechanisms used to support the DSI quality of service under the existing contracts. Appendix C points out that these mechanisms are used as well for service to BPA's other customers and are used by other generating utilities to serve their own customers.

Under the Northwest Power Act, BPA plans firm resources to serve 75 percent of the total DSI requirement, in addition to its other firm loads. As stated in the Senate Energy Report on the Northwest Power Act (p. 59), the balance of the DSI load, that is, the First Quartile, is to be served with resources which are in excess of critical planning amounts but which are operated to meet the entire DSI load "as if it were firm."

Since BPA is not obligated to plan firm resources to meet the First Quartile of the DSI load, BPA uses the flexibility of the Federal hydro system to change the timing for drafting reservoirs to provide First Quartile service, particularly during periods when nonfirm energy is not available. (See Appendix C, Section 3, Borrowing Techniques Used by the Coordinated System.) The techniques available to BPA to serve the First Quartile are defined in the DSI Power Sales Contract. These techniques include direct nonfirm energy when available, borrowed firm energy from the future (FELCC Shift, Advance Energy, and Flexibility Energy), and Surplus Firm Energy Load Carrying Capability (Surplus FELCC) to the extent it is available.

Pertinent parts of the DSI contract are the Shift of FELCC provisions of section 8(b), the Third Quartile restriction rights to recoup such shifted FELCC contained in section 7(e), the Notices and Purchaser Proposals provisions for the Second and Third Quartiles in sections 7(f)(3) and 7(f)(4), the Advance Energy provisions of section 8(c), the Flexibility Energy provisions of section 8(d), and the Surplus FELCC provisions of section 8(e). Additional relevant contract provisions address general principles:

> 8(a)(1). BPA is obligated to and will treat 75 percent of the Industrial Purchaser's Operating Demands as a firm load for purposes of both resource planning and operation, and the remainder of such Operating Demands as a firm load for purposes of resource operation only.
>
> 8(a)(3)(A). The purpose of these efforts by BPA is to achieve the highest possible availability of Industrial Firm Power, consistent with the treatment of the First Quartile as a firm load for purposes of resource operation . . .

The implementation of contract provisions regarding service to the DSI First Quartile involves a great deal of complexity and detail. There are many disagreements over contractual interpretation issues, small and large. This analysis will deal with the more general principles of quality of service and will not attempt to represent solutions to the many problems of interpretation.

Alternative 1.3 Limit Firm Load Changes Within Operating Year

1.3.1 Description of Alternative. This alternative looks at changes which would decrease customer rights under existing Power Sales Contracts to increase their firm load on BPA within an Operating Year. Changes within an Operating Year were a matter of concern for some parties who feared that BPA would be unable to meet operating constraints for fish and wildlife if its load changed greatly from the load used in planning hydro operations for an Operating Year.

The issue initially raised in scoping concerned the DSI contract right to increase Operating Demand up to the level of Contract Demand on 90 days notice to BPA. (DSI Power Sales Contract, section 5(b)(3).) The utility contracts also allow some flexibility for the customer to change its firm load on BPA within the Operating Year; therefore, this alternative encompasses all of BPA's Pacific Northwest customers.

1.3.2 No Action Alternative. In considering this alternative to limit BPA customer ability to change the amount of its wholesale purchase, it must be remembered that utilities must generally follow the changing loads of their retail consumers. If the BPA wholesale contract does not provide flexibility, the utility has to provide its own resources to serve its retail consumers or fail to meet their changing loads.

The existing contracts contain a variety of provisions affecting the customer's ability to change its load within an Operating Year. Some provisions allow flexible changes and some provisions limit changes. BPA did not study an alternative for this EIS which increased BPA's obligation to follow changing customer loads, since this would not be reasonably considered as an alternative and is too radically different a scenario to yield useful information for comparisons. However, the following descriptions of existing contract provisions give an indication of the extent of the potential burden on BPA if customer changes were not limited as they currently are.

1. How do the demands of utility customers relate to BPA's hydro operations? The generic utility contracts do not use the terms "Contract Demand" nor "Operating Demand" as they are used in the DSI contracts. The following discussion describes, for each set of customers, (1) how BPA is given notice of the annual load for which it must plan operations, and (2) what limits constrain the customer in making changes.

For utility customers that purchase on a Metered Requirements basis (see Utility Power Sales Contract, section 13), BPA's forecast of the total needs of Metered Requirements customers is functionally equivalent to BPA's forecasts of DSI loads for purposes of planning operations. A Metered Requirement is the customer's actual load less the actual output of any resources it may own. The loads of these customers may increase or decrease during the year subject to the limitations in section 9 on increases in single loads. If a single load within the customer's service area is expected to increase by 35 aMW in 12 months, or 75 aMW in 60 months, BPA will use best efforts to supply the load but is not obliged to serve it until after a 7-year notice period. For loads increasing 10 aMW or more in 12 months, BPA is not obligated to serve the load until the end of a 2-year notice period.

For utility customers that purchase on an Actual Computed Requirements basis, the customer's Assured Capability and forecasted loads yield something functionally equivalent to the forecasted DSI loads used by BPA for planning operations. There is nothing comparable to DSI Operating Demand that sets limits in advance of the Operating Year on the absolute amounts of peak and energy which may be taken by the Actual Computed Requirements customer. The Actual Computed Requirement is the difference between the customer's Actual Firm Loads, determined monthly after the fact, and the Assured Capability of all the customer's firm resources. The Actual Computed Requirement consists of a Computed Peak Requirement for the year and a Computed Average Energy Requirement for each month of the year. As with the Metered Requirements customer, the loads of the Actual Computed Requirements customer may change and its purchases from BPA may also change within the Operating Year. The section 9 limit on increases in single loads applies to Actual Computed

Requirements customers as well, so increases of this type may not be made within the Operating Year without BPA concurrence. The Actual Computed Requirements customer may also make limited changes in the monthly distribution of its Assured Energy Capability within an Operating Year and thereby change its monthly purchases from BPA. However, these changes, which are described in section 17(d) of the Utility Power Sales Contract must be accounted for in a "Flexibility Account" and must be zeroed out by July 1 of every year. These flexibility changes are similar to provisions in the Coordination Agreement and are subject to similar limits on the magnitude of the redistribution permitted. Computed Requirements customers can change the amount of their purchases from BPA by adding or deleting resources from their Firm Resource Exhibits within the limits prescribed by section 12 of the contract. These changes, however, must be shown in annual submittals, due every January for the following Operating Year, and thus cannot result in changes within the Operating Year.

Planned and Contracted Requirements customers have less flexibility than do Actual Computed Requirement purchasers to make changes in the amount of energy they have a right to take from BPA. The Planned Computed Requirement for peak and energy is fixed for each month of the coming operating year. The Contracted Requirement for peak and energy is set for a 7-year horizon. The distribution of the Contracted Requirement is set for each Operating Year. No more than the planned or contracted amounts may be taken. There is no <u>ex post facto</u> monthly adjustment based on actual loads, as in Actual Computed Requirements. Therefore, the Planned or Contracted Requirements are similar to DSI Operating Demands in that they establish in advance of an Operating Year absolute limits on the amounts of peak and energy which may be taken by the customer. The Planned and Contracted Requirements are also used by BPA for planning operations.

2. How does DSI Operating Demand relate to BPA's hydro operations? Contract Demand is the maximum level of power that can be taken by a DSI under its contracts. Operating Demand may be less than Contract Demand and can be changed more flexibly. The Operating Demand for DSIs is set each April 2 for the coming Operating Year. According to section 5(b)(3) of the DSI contract, it may be increased unilaterally by a DSI on 90 days notice to BPA, but may be decreased only with BPA's consent. Operating Demand may not be greater than the Contract Demand. The Operating Demand is the maximum amount of power the DSI may receive from BPA on any hour (unless BPA authorizes use of auxiliary power).

The Operating Level establishes a DSI's billing demand. On any given hour, the Operating Level is the lowest of the three possible billing demands: Restricted Demand, Curtailed Demand, and Operating Demand. A DSI may request three operating levels a month.

For purposes of planning resource operations, BPA does not use Contract Demands or Operating Demands. Instead, BPA makes its own forecast of DSI Operating Levels based on relevant economic indicators and other information. It is this forecasted load that is used to establish the operating plan and associated rule curves. (See Appendix C for an explanation of rule curves.)

Total DSI Operating Levels have ranged from 63 percent to 97 percent of total Operating Demands and averaged 83 percent of total Operating Demands for 1981-88.

There are obvious business implications for these industries in having a power supply that can or cannot respond to market conditions. As the price of electricity has risen relative to the other costs of aluminum production, this issue has taken on added significance. Before BPA's rate increases starting in 1982 and later, the Pacific Northwest aluminum plants were operated as baseload plants, that is, as near as possible to capacity at all times. Now that electric power rates have increased five fold, the level of Pacific Northwest plant operations is more directly affected by the vicissitudes of the aluminum market.

At the time DSI customers signed these contracts, each DSI requested an Operating Demand at which they expected to operate from the initial date into the future. This Operating Demand might change from time to time, either as defined in Exhibit C at the time of contract execution, or through subsequent customer-requested changes in the Operating Demand schedule of Exhibit C.

In 1981, when the DSI contracts were signed, economic conditions for the DSIs were generally good and the Operating Demands originally set in the Exhibit C's were generally high. By spring 1982, economic conditions had deteriorated and the DSIs were requesting decreases in Operating Demands. BPA granted these decreases contingent on a waiver by the DSIs of their contract right to receive Operating Demand increases on a 90-day notice. BPA has maintained this practice since.

CATEGORY 2: CONSERVATION ALTERNATIVES

These alternatives examine ways in which the Power Sales Contracts could have different effects on the achievement of conservation (including renewable resources directly applied by consumers) by BPA and its Power Sales Contract customers, compared with the No Action Alternative, that is, the existing Power Sales Contracts.

OVERVIEW OF CONSERVATION ISSUES

Northwest Power Act Elevates Conservation. Under the Northwest Power Act, BPA customers may call upon BPA to serve their firm power requirements and BPA is obliged to do so. To fulfill this obligation, BPA received authority to acquire resources. This authority is guided by policies incorporated into the Northwest Power Act with respect to cost-effectiveness, priority for various types of resources, and the Council's Plan. Conservation is the first priority resource and receives a statutory 10 percent cost credit to its favor for cost-effectiveness determinations.

It is important to note that the No Action Alternative includes Pacific Northwest conservation achievement that has occurred since 1981, due to the growing influence of the Power Planning Council's conservation policies, BPA-funded programs, and voluntary utility participation both in BPA-funded and self-funded programs.

The Northwest is recognized as a national and world leader in least-cost planning and conservation resource assessment and acquisition. BPA believes that the region's progress with conservation is due to an appropriate allocation of responsibility among diverse entities, including BPA, the Council, all utilities, utility regulatory bodies, States, local governments and consumers. BPA has implemented a number of conservation programs designed to foster Pacific Northwest conservation. These programs have been implemented outside the Power Sales Contracts and have not been impeded by them.

- BPA spent approximately $880 million on conservation programs in the Northwest between 1982 and 1990. IOUs and the larger public utilities made additional expenditures to implement their own non-BPA conservation programs.

- BPA programs have resulted in energy savings of about 300 aMW. Utility programs have achieved significant additional energy savings.

- Changes in building codes and utility marketing programs have made new residential construction more energy-efficient.

- In large measure, the region's utilities now have the ability to acquire conservation in the existing residential sector.

- Regional programs to improve energy efficiency in new commercial buildings have begun only in the last few years.

- State regulators are considering appropriate rate treatment and incentives for conservation investments.

- Utility regulatory commissions are adopting least-cost planning processes and are considering options for rate treatment for conservation investments.

Issues Outside the Contracts. The conservation alternatives do not examine certain extra-contractual policy issues outside the Power Sales Contracts, such as determinations of cost-effectiveness and BPA decisions on levels of programmatic funding for conservation. These issues clearly can have powerful effects on conservation. For example, changing criteria for cost-effectiveness could have significant effects on the amount of conservation available for programs in the region. Likewise, if BPA funding levels went to zero, or increased to provide incentive levels much higher than current policy, the effects could be greater than either of the two contractual alternatives analyzed here.

These policy decisions are addressed by BPA, the Council, and others in other processes such as BPA's Resource Program, the Council's Northwest Conservation and Electric Power Plan and amendments thereto, and BPA's budget process. The environmental impacts of alternative resource types are the subject of analysis in the Resource Program EIS, which is under preparation. The results of the Resource Program EIS analysis will be used to help to decide which resources BPA should acquire to meet loads. This analysis will focus on two alternatives pertaining to the contract provisions:

Alternative 2.1, Conservation Compliance as a Condition of Service, in which the customer's obligation to implement conservation is changed via the Power Sales Contracts; and Alternative 2.2, Conservation Transfers Facilitated, in which customer ability to implement conservation and sell it as a resource is potentially facilitated by removing a contractual prohibition against resale of Federal power.

Eligibility for BPA-Funded Voluntary Conservation Programs. BPA, the utility, and the consumer usually share the costs of conservation. BPA's conservation cost-sharing policy provides that customers who are not purchasing at least 1 percent of their firm power requirements from BPA may not receive conservation funds from BPA, since they do not contribute sufficiently to payment of conservation costs included in BPA rates. The implication of this policy is that BPA's IOU customers cannot participate in BPA-funded programs until they place load on BPA. Since only one of BPA's IOU customers currently plans to place long-term firm load on BPA through the Power Sales Contracts, BPA cannot be assured that it will get the benefit of the conservation resources developed in IOU service areas.

MCS and BPA's Conservation Surcharge Policy. BPA's Model Conservation Standards (MCS) Surcharge Policy (Surcharge Policy) requires customers covered by the Surcharge Policy to implement BPA-approved energy conservation standards and programs. Customers of BPA within the Pacific Northwest region that purchase firm power, and utilities participating in the Residential Exchange are subject to the Surcharge Policy. Those customers can comply with the terms of the Surcharge Policy by either enrolling in the appropriate BPA program, developing their own program as a substitute for BPA's, or relying on codes or service standards set at levels specified by the Council's MCS. If a customer falling under the terms of the Surcharge Policy does not adopt BPA-approved standards or programs in its service area, its power billing can be increased and its Residential Exchange benefit can be reduced.

To date, every customer of BPA who comes under the terms of the Surcharge Policy has an approved plan for both the residential and commercial sectors. The number of utilities promoting more efficient residential building standards through a utility program, utility service standard, or jurisdictional adoption of the appropriate codes has increased substantially since implementation of the Policy. The practical impact of recent changes in the Council's Model Conservation Standards for commercial buildings is that utilities will have greater responsibility for ensuring the inclusion of all cost-effective energy savings in new commercial construction. Since cost-effectiveness changes with technology and energy prices, it is impractical for regulators to attempt to implement building codes which meet this standard. Instead, utilities tend to rely on the alternative provisions of the council's commercial MCS rule which allow utilities to adopt the BPA program or submit programs which will provide equivalent savings. To date, utilities serving the vast majority of new commercial loads in the region have implemented programs to capture all cost-effective savings.

Aluminum Smelter Conservation/Modernization (Con/Mod) Program. In 1986, BPA implemented the Aluminum Smelter Con/Mod Program. The goals of this program were (1) to encourage near-term modernization of the region's aging aluminum smelters to make them more competitive in the world aluminum market, and (2) to acquire conservation from the aluminum smelter efficiency improvements to be used to serve other loads as the region continues to grow economically. All 10 of the region's aluminum smelters are participating in the Program. Under the program, BPA pays an incentive to the smelters based on the level of verified energy savings acquired from operating modernized smelters. BPA will reduce the aluminum companies' Contract Demand to ensure conservation is acquired based on the reduction in required power that results from the energy efficiency improvements at the smelters.

Alternative 2.1 Conservation Compliance As A Condition of Service

2.1.1 Description of Alternative. For this alternative, the Power Sales Contracts are assumed to require conservation achievement by BPA customers. This is somewhat different from the existing contracts which facilitate conservation and provide disincentives for failure to implement conservation, but do not direct the customers' implementation of conservation.

2.1.2 No Action Alternative. It was noted in the Overview that there are a number of issues which have been debated in the Pacific Northwest that can affect conservation achievement by utilities. A contract provision requiring conservation would not resolve the following issues:

- Use of regional versus utility-specific cost-effectiveness determinations. BPA customers make individual assessments of resource cost-effectiveness. Their avoided costs may be BPA's wholesale rates, not BPA's marginal cost of new resources. Utilities may also have a different discount rate for evaluating alternatives and costs.

- Appropriate ratios for BPA/utility cost sharing.

- BPA funding to the level of cost-effectiveness to the consumer.

- BPA budget constraints.

- Different State laws and regulatory principles regarding conservation.

The scoping process revealed some general public uncertainty about the way the Power Sales Contracts treat conservation as compared to electric power generating resources. Respondents asked that it be shown specifically how the Power Sales Contracts accord conservation its proper priority as a resource. The major questions are as follows:

(1) How are generating resources accounted for in the contracts?
(2) How is conservation accounted for in the contracts?
(3) Are customers allowed by the contracts to ignore conservation?
(4) Do the differences in accounting for generating resources and conservation constitute a disincentive?

These questions are addressed in the analysis of impacts for this alternative, in section 2.1.2 of Chapter 4.

Alternative 2.2 Conservation Transfers Facilitated

2.2.1 Description of Alternative. Under this alternative, we look at the effects on the Power Sales Contracts of conservation transfers. In a conservation transfer, a purchasing utility funds conservation in the service area of the conserving utility. The conserving utility can then sell or displace to the purchasing utility an amount of electric power which has been "freed up" by the conservation.

Conservation transfers became an issue of interest in the Pacific Northwest as it was realized that some IOUs may need to add resources before BPA and most of BPA's preference customers. There may be conservation potential in preference customer service areas which could be a cost-effective resource alternative for IOUs. The 1986 Council Plan called for BPA to consider facilitating conservation transfers among Northwest utilities to enable a utility with a conservation resource to transfer the BPA power it would otherwise have consumed to a purchasing utility, thus providing funds for conservation.

BPA approaches conservation transfers with care because of the statutory and public policy issues regarding the resale of Federal firm requirements power by a utility customer. There are other significant implementation questions that must be addressed for any conservation transfer, even if requirements power is not being directly transferred or resold:

(1) the size and cost of the resource available for transfer;
(2) the appropriate cost-effectiveness criteria for a resource transfer which BPA facilitates in the event it could create lost opportunities in retrofit programs;
(3) verification of the conservation savings;
(4) allocation of the resource performance risk; and
(5) term of the transfer contract.

For this alternative, we will assume that the increased transactions involving conservation transfers involve the resale of entitlement to firm requirement power, including Federal Base System (FBS) resources, because that is the only conservation transfer transaction that is prohibited by the Power Sales Contracts. Other types of conservation transfers between utilities can already take place with only minor adjustments under the utility's Power Sales Contract, as long as requirements power is not being resold.

This alternative is different from the pilot program being developed by BPA and several customers. In the pilot program, BPA would make a sale of surplus power to a preference customer for resale to another utility. In consideration, the preference customer would agree to implement cost-effective conservation in its service territory. The surplus power is subject to recall to meet BPA's firm loads.

2.2.2 No Action Alternative. Conservation transfers can take place under the existing contracts in the following ways:

- Conservation by BPA customers stretches BPA surplus. Conservation developed by utilities in their own service territories has contributed to the surplus that BPA markets to Pacific Northwest and Pacific Southwest utilities.

- More long-term placement of utility load growth on BPA would allow BPA-funded conservation to be "transferred" or shared among a greater number of Pacific Northwest utilities. If BPA were the sole resource supplier for the region, as examined under Alternative 3.2, BPA as Regional Supplier, conservation would be transferred among Pacific Northwest utilities automatically as BPA's regionwide conservation programs freed up BPA's generating resources to serve preference customer and IOU requirements.

- BPA customers with generating resources or power contract rights other than their BPA purchase can transfer those resources in exchange for conservation funding from other utilities with no impediment from the Power Sales Contracts, assuming such resources are not dedicated to meet firm load under the Power Sales Contract.

The Power Sales Contracts (GCP 56) prohibit the resale of requirements power. This prohibition assures that FBS resources as defined in the Northwest Power Act would remain available for service to public bodies, cooperatives, and Federal agencies, consistent with section 5(b)(6) of the Northwest Power Act.

CATEGORY 3: RESOURCE PLANNING AND DEVELOPMENT ALTERNATIVES

This category addresses those alternatives whose major effects would be upon the type, timing, and cost of resources to BPA and the Pacific Northwest region. There are several major alternatives, all of which primarily affect the need for planning and developing resources.

OVERVIEW OF RESOURCE PLANNING ISSUES

INSTITUTIONAL ROLES

The Power Sales Contracts establish some important conditions which must be taken into account by the region's electric power planners. Some of these conditions have been referred to as the "institutional roles" question. Institutional roles in regional resource planning are played by BPA, the Council, regional utilities, and state utility regulatory bodies. The Northwest Power Act created a role for BPA as a regional resource provider and for the Council as a planning body. The Northwest Power Act did not diminish the roles and responsibilities of utilities to make independent resource decisions. Section 10(a) of the Northwest Power Act states, among other things, that the rights of utilities to develop and implement plans and programs for the conservation, development, and use of resources are not affected or modified. The existing contracts are consistent with that statutory direction.

Institutional roles issues figure largely in Alternative 3.1, Certainty of Load Placement on BPA; Alternative 3.2, BPA as Regional Supplier; and, to some degree, in Alternative 3.5, Shorter Contract Terms. The other two alternatives--3.3, Customer Planning on Other Than Critical Water Basis, and 3.4, Improved In Lieu Provisions--are concerned with conditions affecting the economics of resource planning and development.

RESOURCE PLANNING AND DEVELOPMENT PROCESSES

There are many resource planning and development issues which are not controlled by these Power Sales Contracts. Cost-effectiveness of resources, and strategic planning for uncertainty are only two. Resource planning and development decisions are all made outside these contracts. BPA decisions are made in its Resource Program and resource acquisition processes. The environmental impacts of alternative resource types are the subject of analysis in the Resource Program EIS, which is under preparation. The results of the Resource Program EIS analysis will be used to help to decide which resources BPA should acquire to meet loads. The Council's planning for the region is done as a separate public process. Each of BPA's utility customers develops its own resource plans and activities. State utility regulatory bodies are also involved in the resource plans and activities of IOUs, especially with respect to mandates requiring utilities to use least-cost planning.

Alternative 3.1 Certainty of Load Placement on BPA

3.1.1 **Description of Alternative**. The contracts affect BPA's certainty about its future loads by allowing customers to change the amount of their purchase after giving notice. These changes could increase or decrease BPA's firm load for which firm resources must be acquired. Under this alternative, BPA would have better certainty as to its loads because customers must give longer notice of changes, i.e., 10-year notice instead of 7-year notice.

3.1.2 **No Action Alternative**. All three types of contracts contain provisions allowing for changes in the amount of power purchased by the customer. This alternative concerns the provisions in the Utility Power Sales Contracts specifically, because utility customers may add or delete resources of their own that they may use to serve their firm loads. This results in a corresponding change in the amount of load BPA must serve. DSI customers may change the amounts they purchase from BPA, but may not decrease BPA purchases by using other resources or other suppliers. Changes in DSI Operating Demands are studied under Alternative 1.3. Likewise, the notice periods for changing the amount of power exchanged under the Residential Exchange Agreement is studied elsewhere, under Alternative 3.4.

The Utility Power Sales Contracts have a number of provisions controlling a customer's ability to change the amount of power it purchases from BPA. These are found in Section 12, Purchaser's Firm Resources, and in Section 17, Purchaser's Computed Requirements and Amount of Power Sold. A 10-year notice period was discussed during the original negotiations, but the parties eventually agreed on a list of notice requirements for specific circumstances which may be reflected in the annual Firm Resource Exhibit submittals each January 1. These are described in Appendix B.

As a result of these provisions, BPA has increased uncertainty about the size of its load beyond the seventh year of its planning horizon compared to a flat 10-year notice requirement. It has been suggested that this could result in different resource planning decisions than BPA would have made if it had longer certainty, such as 10-year notice. The following Alternative 3.2, BPA as Regional Supplier, looks at a longer period of certainty, such as 20 to 30 years, when it analyzes the effects of an alternative in which only BPA acquires resources for regional load growth.

BPA has recently addressed this uncertainty problem by deciding to plan resources only for load it has contractual notice to serve. This policy decision was first reflected in BPA's 1987 Resource Strategy. In practical terms, this means that BPA assumes it has no obligation to plan resources to serve IOU load growth. This contractual uncertainty applies to public agency customers as well as IOUs; however, we are focusing on IOUs because these customers have forecast zero requirements purchases from BPA for the 7-year horizon covered by the Power Sales Contracts.

Alternative 3.2 BPA as Regional Supplier

3.2.1 Description of Alternative. This alternative will assume that all regional load growth is served by BPA; that is, that customers do not develop their own resources or purchase from other suppliers. This concept has been previously examined by BPA in its resource program and the Northwest Power Planning Council in the development of its Plan. The issue of how much Pacific Northwest load is or should be served by BPA is significant because the primary method of effectuating the Northwest Power Act resource priorities and the Council's Plan is through BPA resource acquisition procedures under section 6(c) of the Northwest Power Act. If a great proportion of regional load growth is not served by BPA, there is concern that Northwest Power Act resource priorities will not be realized, that the region's total resource costs will be unnecessarily high, and that other advantages of the existing Federal system and assumed economies of scale will be lost. However, the Northwest Power Act specifically avoided modifying utility rights to plan and develop conservation and generating resources, among other things (section 10(a)). In view of the provisions of the Northwest Power Act regarding utility autonomy, BPA has focused on improved competitiveness in order to fulfill its role as a resource supplier. Despite these concerns, considering institutional and technological trends toward independent utility marketing and smaller resources, it is also possible that utilities may develop resources consistent with least-cost planning and the Northwest Power Act priorities, and achieve any available economies of scale even if load growth is not placed on BPA.

3.2.2 No Action Alternative. BPA's Utility Power Sales Contracts generally allow customers to acquire their own resources, including power contracts from other suppliers, limited by the duty to give notice to BPA (Utility Power Sales Contract, section 12(b)). DSI customers may not acquire resources to serve their loads, nor may they buy from other suppliers. Some policy considerations related to resource priorities are addressed as well in the Utility Power Sales Contracts. Customers agree to use best efforts to acquire resources in accord with Northwest Power Act priorities to serve their own load growth (section 5). In addition, GCP 45 indicates that the parties will negotiate amendments if necessary to allow the Council's Plan and Fish and Wildlife Program to be effective.

As mentioned before, the Northwest Power Act gave BPA authority to acquire resources and significant borrowing authority to fund conservation. It had been envisioned that this would lead to a situation in which Pacific Northwest utilities would develop resources and BPA would acquire their output. The regional power supply would be assured, and costs and benefits would be generally shared. This concept is evident throughout the Utility Power Sales Contract in sections dealing with BPA resource acquisitions and provisions to assure that utilities that develop resources receive their full benefit. Though the contracts allow utility customers to acquire their own resources, this scenario of regional resource planning could have been effectuated by voluntary customer load placement on BPA. Some customers do not currently voluntarily place load on BPA. Several developments brought this about:

1. Shortly after the Northwest Power Act was passed, BPA's load/resource forecast turned from deficit to surplus.

2. At the same time, the West Coast need for resources was generally declining, with many utilities being surplus.

3. BPA customers objected to lack of long-term certainty as to BPA rates and to other details of service under the Northwest Power Act contracts.

4. Utilities were increasingly held to account by certain groups for actions in terms of specific benefit to their own retail customers, rather than to a regional cost-effectiveness standard. This is seen in some State PUC decisions and in the positions of ratepayer interest groups, boards, and municipal councils.

All this led some BPA customers to refrain from committing to purchase long-term firm requirements from BPA. BPA and the Council have both addressed this dilemma in public processes such as BPA's Resource Program and the Council's Plan.

Even though the centralized regional resource development under the Northwest Power Act is not required by the Power Sales Contracts, the resource priorities of the Northwest Power Act have been effectuated for BPA's purchasing customers. Much of BPA's long-term firm load comes from customers without significant alternative resources. By serving these customers under the Power Sales Contracts, BPA spreads some benefits of conservation and cost-effective resource planning.

Alternative 3.3 Customer Planning on Other Than Critical Water Basis

3.3.1 Description of Alternative. This alternative assumes that the Power Sales Contracts allow customers to plan their resources based on criteria other than critical water planning. The planning criterion used by a utility affects the amount of investment it will make in new resources and the reliability of service it will provide to its customers and the degree to which other neighboring utilities may be affected by a resource shortfall for one utility. Alternatives to critical water planning are a major subject of analysis in the SOR EIS.

3.3.2 No Action Alternative. The critical water planning criterion generally used in the Pacific Northwest assures service to firm loads under the worst streamflow conditions of record. This is the system's Firm Load Carrying Capability. This planning basis supports high reliability of service. Different planning criteria, such as average water, result in less investment in resources and greater probability of failure to serve load. Critical period planning is practiced under the Coordination Agreement to which all Pacific Northwest generating utilities except the Idaho Power Company are parties. While the Coordination Agreement does not mandate resource acquisition by any party, the rights of the parties to various Coordination Agreement benefits are tied to the critical period planning criterion.

The Utility Power Sales Contracts thoroughly incorporate critical period planning criteria for customer resources. Like the Coordination Agreement, the Power Sales Contracts stop short of requiring utilities to invest in resources to meet this criterion.

Utilities and other entities such as the Council have been interested in alternatives to critical period planning which may be less costly. The Power Sales Contracts were written with the understanding that any utility's failure to maintain firm resources based on critical period planning could result in disadvantages to others. These disadvantages could range from costs to acquire new resources to help serve the short utility, to loss of load in the event of broad-reaching governmental curtailment proceedings. Full requirements customers were concerned that their rates would be increased to cover the costs of new resources for other BPA customers. Therefore, some existing contract provisions create disincentives for failing to maintain sufficient resources. For reasons detailed below, these disincentives have their strongest effect on Actual Computed Requirements Customers. These customers are Seattle City Light, Tacoma City Light, Grant PUD, Chelan PUD, Douglas PUD, Eugene Water and Electric Board, Cowlitz County PUD, and Snohomish PUD.

The Power Sales Contract disincentives to noncritical water resource planning are as follows:

1. A requirement that Contracted Requirements purchasers not request any regionwide load curtailment programs prior to purchasing available high-cost resources (Section 17(b)(9)). This is intended to require the utility to bear the cost of risk of inadequate resources before resorting to measures that affect other utilities.

2. BPA ability to charge an Actual Computed Requirements purchaser an availability charge for the unused portion of its full Computed Requirement, which is calculated based on critical water capabilities of the purchaser's resources (Section 17(g)). The availability charge decreases economic advantages that might be gained through less expensive, riskier resource plans.

3. The provisions for allocations in event of insufficiency in section 7 compute the size of the allocation based on critical water assumptions for rating the customer's resources. The surplus throughout the 1980's made this disincentive somewhat remote for most utilities.

Disincentives 1 and 3 have a weak effect during periods of regional surplus, so disincentive 2, which applies only to Actual Computed Requirements customers, had the strongest effect until the end of the period of surplus. The other discincentives can be expected to be more influential now that the surplus has ended. As explained in Appendix B, Metered Requirements customers generally do not engage in Coordination Agreement planning and could not make significant use of this alternative. Metered Requirement customers are required to purchase the amount by which actual loads exceed the actual contributions of their own resources. Therefore, the customers have no significant opportunities to affect their billing from BPA by using different calculations of the planned capabilities of their resources.

Alternative 3.4 Improved Ability to Exercise Provisions to Make Purchases In Lieu of Exchanges Under the Residential Exchange Contracts

3.4.1 **Description of Alternative**. This alternative assumes that BPA can make purchases in lieu of exchanges with less constrictive notice provisions. The in lieu provisions of the Residential Exchange contracts would be assumed to be changed to allow more flexible use by BPA on shorter than 7 years' notice, such as 1 or 2 years' notice. It will also be assumed that BPA surplus can be used and that the in lieu purchase could be for less than 5 years. BPA projects no exercise of in lieu purchase provisions during the study period, so none is assumed for the Base Case.

3.4.2 **No Action Alternative**. BPA's Residential Exchange contracts allow BPA to purchase resources other than the utility's exchange power under certain circumstances and conditions. BPA must give 7 years notice before making in lieu purchases under the Residential Exchange contracts. The in lieu purchase must last at least 5 years. Some parties argue that BPA surplus cannot be used as the in lieu resource, but BPA's position is that this is not prohibited by the contract.

An important element of the residential exchange concept is found in section 5(c)(5) in the Northwest Power Act. This section allows BPA to acquire power from other resources in lieu of accepting power offered by the exchanging utility. The Northwest Power Act specifies conditions on BPA's rights to acquire in lieu power:

1. The cost to BPA of acquiring in lieu power must be less than the cost of purchasing power offered by the exchanging utility;

2. Acquisitions by BPA for in lieu purposes must be subject to provisions of sections 4 and 6 of the Northwest Power Act.

When BPA negotiated provisions of the generic Residential Exchange agreements, utilities were concerned that BPA would use the in lieu rights to force surpluses--caused by imprudent BPA resource acquisitions--upon exchanging utilities. Because of those concerns, BPA agreed to additional restrictions, beyond those mandated by statute, on its ability to exercise in lieu rights.

Under the existing contracts, to exercise the in lieu provision, BPA must provide 7-year notice (starting at any time) of intent to acquire an in lieu resource. The notice must state the amount, duration, source, estimated cost, and estimated scheduling provisions of the intended acquisition. The proposed acquisition must be at least 5 years in duration.

The utility must respond within 60 days of the notice by either (1) reducing its ASC for the portion of its load to be served by the in lieu resource to the cost of the intended in lieu acquisition; or (2) reducing the amount of power they obligate BPA to purchase from them by the in lieu quantity. In both cases, BPA is to continue to sell the utility at the PF rate an amount of power equal to the utility's residential and small farm load. The utility cannot respond by dropping out of the exchange.

There are several other issues involved in a decision to make a purchase in lieu of exchange.

- What should be the basis for selecting utilities for which "in lieu" purchases would be made? Highest ASC? Earliest deficit? Largest exchange load?

- There is a risk to BPA of high-cost acquisitions if surplus projections are wrong and power expected to be surplus is used for "in-lieu" purchases is subsequently required for firm loads.

- Consistent with the above risk of overestimation of surplus, is or should in-lieu power be subject to recall provisions? Could BPA recall its surplus from in-lieu use? Could other sellers recall in-lieu sales?

- What is the appropriate in-lieu cost comparison? Should fully-allocated resource costs or levelized resource costs be compared with in-lieu utilities' average system costs?

- What procedure is appropriate, e.g., for NEPA and public involvement requirements, etc.?

Alternative 3.5 Shorter Contract Terms

3.5.1 Description of Alternative. This alternative assumes that the Power Sales Contract terms were for 10 years rather than 20 years, e.g., expiration in 1991. This alternative includes no assumptions regarding novel forms of service after 1991. When the alternative of 10-year contract terms was proposed, the major issue was to increase flexibility to make major changes in the contracts at an earlier date.

This EIS examines the effects of a variety of major contract changes in other alternatives. Alternatives 1.1, 2.1, and 3.2 analyze changes that would relate to the Council's Plan and Fish and Wildlife Program. Other alternatives show the impacts of other changes. Therefore, this alternative concentrates on the effects of shorter contract terms on customers.

This alternative assumes that BPA customers retain all rights and entitlements to BPA power that they now possess. BPA's mandates as a power marketing agency are still in force. Preference customers are entitled to access to the Federal Base System resources. All BPA utility customers have Northwest Power Act rights under section 5(b) to request that BPA serve their requirements. IOUs may purchase their requirements from BPA subject to a 5-year cancellation of contract notice if such energy is needed to satisfy the requirements of public bodies and cooperatives.

The only new assumption is that BPA will not commit to supply for longer than 10 years. This will have its effect, if any, on customers who are vulnerable to uncertainty of supply and on those who are most active in independent resource development.

As previously noted, BPA's utility customers have increasingly pursued resource independence. Most IOUs currently plan no long-term purchases from BPA under these contracts. Some of the large preference customers have declared their interest to look at future sources of supply other than BPA. Preference customers without significant generating resources and without active plans to look for other sources of supply have the greatest expectation that BPA power will be available to them for many years in the future. The 10-year contract term would not be expected to significantly change their actions. Shorter contract terms might affect the decisions of BPA's DSI customers. Lack of long-term electric power supply certainty from BPA could lead DSI customers to turn to other Pacific Northwest utilities in 1991. In that case, BPA might indirectly supply power to this load. In that case, BPA would not necessarily receive the benefit of reserves currently provided by DSI contracts, and might have to replace those reserves. Generally, a shorter contract term could be expected to discourage customers from relying on BPA as a long-term supplier of power.

3.5.2 No Action Alternative. All the contracts studied here have 20-year terms which expire in 2001. Section 5(a) of The Bonneville Project Act limits BPA contract for the sale of electric energy to terms not longer than 20 years. Section 5(b) of the Northwest Power Act required BPA to offer "long term" contracts to its utility and Federal agency customers. Section 5(d) required BPA to offer initial "long term" contracts to its DSI customers. The legislative history of the Northwest Power Act indicates that Congress contemplated that 20-year contracts would be offered. (House Report 96-976, Part 1, pp. 61, 6.3)

In BPA's September 1981 Environmental Report on the contracts, the effects of shorter terms, such as 5 or 10 years, were discussed. (Chapter 22, pp. 2-3.) In general, the 20-year term was considered to be appropriate for requirements sales from a supplier who was intended to be the primary source of supply for its customers. Resource participation contracts and transmission agreements in the electric utility sector are frequently much longer, e.g., 30 to 40 years. Historically, BPA has offered its requirements purchasers 20-year contracts.

As described in the discussion of impacts, BPA's analytical models assumed for the Base Cases that the contracts were extended indefinitely. The analysis will show the planning effects of longer than 20-year contracts. Longer-than-20-year contracts would also have effects on the more subjective areas of certainty and risk, both for BPA and its customers.

CATEGORY 4: QUALITY OF SERVICE AS A RESOURCE CHOICE

OVERVIEW OF QUALITY OF SERVICE ISSUES

This is a potentially broad topic which is only partly within the scope of this EIS. At its broadest, the issue of quality of service as a resource choice arises in discussions regarding the critical water planning basis and the firming of non-firm energy. The Council has expressed interest in these concepts, but they far exceed the scope of this EIS in that they involve the Coordination Agreement and larger public policy issues not addressed in the Power Sales Contracts.

As noted in section 1.6, BPA is preparing two other EISs that treat issues of resource development and operation. The Resource Program EIS discusses and analyzes issues related to the development of resources for the region. And the SOR EIS will address operational considerations regarding the FCRPS and its multiple uses. Because these separate processes are occurring, decisions regarding resource operations and development will not be made based solely on the analysis in this EIS.

Our subject matter concerns two areas:

(1) the resource choices reflected in existing DSI quality of service provisions, and

(2) the applicability of these concepts to non-DSI customers.

In general, the alternatives in this category look at changing the quality of service to a portion of the customer's load. Any potential future negotiations between BPA and its customers on quality of service would undoubtedly uncover other options in addition to those studied here. Also, negotiations would involve practical implementation issues and tradeoffs among contract provisions which cannot be analyzed here. Rate changes to reflect the change in service quality are among the important details not dealt with in this EIS.

BPA's most recent effort to study quality-of-service changes was between 1984 and 1986 as part of the DSI Options Study. The quality-of-service changes examined in the DSI Options Study involved offering the DSIs a rate reduction in exchange for increasing the amount of DSI load subject to First-Quartile-type service. Strictly for the purpose of performing sensitivity analysis for this option, rate credits ranging from 3 mills/kilowatthour (kWh) to 6 mills/kWh were chosen. No attempt was made in the DSI Options Study to develop any proposed credit or analyze the value or the cost of changing the amount of DSIs load subject to First-Quartile-type service.

The actual amount of any rate credit or payment BPA would offer for increased First-Quartile-type service was an implementation issue that was beyond the scope of the Options Study. The determination of a rate credit or BPA payment for increased interruptibility will be subject to negotiation and will be based on the value to the power system and the cost to the DSIs of increased interruptibility. The level of the rate credit for increased First-Quartile-type service is not addressed in this EIS for the same reasons that it was not addressed in the DSI Options Study. In this EIS, the DSI rate is not adjusted for any increased interruptibility due to changes in the amount of First-Quartile-type service.

The Option Study looked only at increasing interruptibility to the DSIs, not other customers. In this EIS, the increased interruptibility alternative is considered for both DSIs and non-DSI customers. No specifics on amounts of power or non-DSI loads that might be affected are available at this time. Nevertheless, some non-DSI customers may be attracted by a rate credit and may wish to be considered as candidates for that quality of service for portions of their load.

Alternatives 4.1, 4.3, and 4.4 look at increasing or decreasing the amounts of load which are subject to an interruptible quality of service. Alternative 4.2 looks at a special feature of existing DSI interruptibility provisions.

Alternative 4.1 Increase First-Quartile-Type Interruptibility

4.1.1 Description of Alternative. This alternative looks at the effects of increasing the amount of currently-firm load that is subject to the same quality of service provisions as the DSI First Quartile under the current contract. This concept was initially examined in the DSI Options Study for application to DSI load only. This alternative goes beyond increased DSI interruptibility to look at extending this type of quality of service to customers that are not DSIs.

When this concept was considered in the 1985 DSI Options Study, BPA concluded that the interruptibility option was best viewed as the equivalent of a resource acquisition, that is, BPA would essentially pay the customer to release BPA from its obligation to acquire resources to serve a certain amount of load. Based on the outlook for the region's load/resource balance at the time that option was considered, BPA concluded that the option should not be pursued for several years. Consequently, the increased interruptibility option was not environmentally analyzed in the DSI Option EIS.

This alternative deals with two quality of service issues:

(1) not having to acquire resources to serve the load, and

(2) the right to restrict such load at any time for any reason to meet BPA's firm obligations or displace Federal system resources.

The alternative includes two cases:

Case A: An amount of firm load equal to 50 percent of DSI load is converted to the same quality of service as the First Quartile. All remaining load is firm on both a planning and an operational basis. If this is assumed to be DSI load, the Third Quartile is still a firm load and therefore can be restricted to replace service with borrowing techniques. (See Appendix C for detailed description.) Therefore, the same techniques used to serve the First Quartile under the existing DSI Power Sales Contract are available to serve increased DSI load subject to First-Quartile-type service.

Case B: First Quartile service rights are expanded to an amount of load equal to 100 percent of the DSI load. Service to all such load, DSI or other customers, is provided by excess energy, either nonfirm energy or surplus firm energy, or purchased power if available. Borrowing techniques are not used to serve any portion of the DSI load because the Third Quartile is not firm and therefore cannot back up this type of service.

4.1.2 No Action Alternative. Under the No Action Alternative, most BPA customer load is served as firm, that is, BPA is obliged during the term of the contract to serve such load with a high degree of certainty. For all utility loads and three quartiles of DSI load, the Power Sales Contracts oblige BPA to plan, acquire and operate sufficient resources to serve such loads and to avoid interruptions. (The DSI Second and Third Quartiles are subject to certain restrictions under special circumstances that are described in Alternative 4.4.)

The DSI Power Sales Contract section 8 provides that BPA is not obligated to plan or acquire new resources to meet First Quartile loads, but, instead, BPA is obligated to treat the First Quartile as a firm load in operating existing resources. On an operational basis, BPA provides First Quartile service through a combination of nonfirm energy and borrowing techniques, that is, energy borrowed from the future. (See Appendix C for a detailed explanation of borrowing techniques.)

The First Quartile has a high priority for service from existing resources when nonfirm energy is available. In addition, in order to treat the First Quartile as firm load for purposes of resource operation, BPA uses borrowing techniques whereby planned firm power is moved among time periods to the extent such techniques are prudent and permitted by contract or other operation limitations. In the event BPA needs the borrowed energy in the future, BPA can restrict the DSIs Third Quartile, which serves to replace or return the borrowed energy. (The Third Quartile restriction rights that are specifically tied to backing up service to the First Quartile are contained in section 7(e) of the DSI Power Sales Contract.)

In addition to quality of service provisions in section 8 of the DSI Power Sales Contract, BPA has a right to restrict service to the DSI First Quartile as provided in section 7. Each of the various restriction rights contained in section 7 is an independent right which may be exercised separately or in combination with the others. Section 7(c) applies only to the DSI First Quartile. It provides that BPA may restrict the First Quartile at any time for any reason in order to protect BPA's ability to meet its firm obligations or displace Federal system resources. (See Alternative 4.4, below, for a description of BPA's other restriction rights under section 7.)

This alternative was originally raised in connection with DSI service; however, utilities also serve industrial and other loads which could also be interrupted given certain modifications to the Utility Power Sales Contracts. Under the Utility Power Sales Contracts, BPA's obligation to serve is limited to firm load. Section 3(b) defines Actual Firm Peak Load and Actual Firm Energy Load. This definition specifically excludes "...any load to the extent the Purchaser had a unilateral right to interrupt such load during such month, even if such load was not actually interrupted . . . ."

A qualified exception is provided for Actual Computed Requirements customers under section 17(e), which addresses load curtailment arranged for by the utility for the purpose of supporting the assured capability of its firm resources in the event those resources are unable to produce their planned Assured Capabilty. In such a case, the curtailed load would be included as part of Actual Firm Load. If the load was curtailed in accordance with section 17(e) and BPA's procedures, the amount of energy curtailed would be determined and added back into Actual Firm Load for the purpose of calculating the Computed Requirement. If this were not done, the Computed Requirement formula would allocate the utility a lower amount of power it would have a right to receive from BPA at a time when it was unable to generate its full assured capability from its own resources. To date, only one customer (Chelan County PUD) has made use of this section.

Alternative 4.2 No BPA Purchase Required for Certain Exercise of First Quartile Restriction Rights

4.2.1 Description of Alternative. This alternative looks at the effects of changing a condition that must be met before BPA can exercise the contractual restriction rights for the First Quartile of DSI load that BPA had planned to serve with shifted FELCC. Currently, BPA must endeavor to purchase or recall energy which it would have purchased or recalled to serve other firm loads. This alternative would modify this requirement such that BPA would not be required to attempt to purchase or recall energy prior to exercise of this restriction right during periods for which BPA had previously shifted FELCC to serve the DSIs.

4.2.2 No Action Alternative. Section 7(c)(2) of the DSI Power Sales Contract states that, during any portion of a Contract Year into which BPA shifts FELCC to serve all or a portion of a DSI's First Quartile load, BPA shall retain its restriction rights as to the First Quartile, but shall acquire or recall any electric energy which it is legally authorized to acquire or recall, and which is available at a Reasonable Cost, before restricting or continuing to restrict that portion of the DSI's First Quartile. When BPA shifts FELCC into a current Operating year to serve the First Quartile, the risk that such FELCC will be needed in a future Operating Year is covered by BPA's right to restrict the Third Quartile if necessary and as provided by the contract. Therefore, BPA's otherwise-firm obligation to serve the Third Quartile is moved with the shifted FELCC to the current operating year for the First Quartile. When this shift has occurred, the First Quartile becomes a firm load for a time; hence, BPA has an obligation to acquire resources at Reasonable Cost or recall energy to avoid First Quartile restrictions. Generally, this obligation exists in one or more of the months from September through December of every year in which hydro system reservoirs have refilled, i.e., the first year of the critical period.

Reasonable cost is defined in section 14(i)(3)(k) of the DSI contract as "that cost of electric power and energy up to a level fixed by power supply circumstances based on the price that Bonneville would prudently pay for a resource at a given time to prevent restriction of a Firm Obligation. The cost of a resource acquired by Bonneville, the use or operation of which is deferred until a later period in the Coordination Agreement Critical Period by means of shifting FELCC for the benefit of firm loads or by other similar techniques, is a Reasonable Cost for the amount so deferred."

Alternative 4.3 Increase Quality of Service to First Quartile

4.3.1 Description of Alternatives. This alternative looks at a scenario in which the entire DSI load is firm, that is, resources must be acquired to meet this load. Also, this load does not provide reserves to BPA through contractual restriction rights.

4.3.2 No Action Alternative. The existing DSI contract provisions on service to the First Quartile were described in Alternative 4.1 under the No Action alternative.

Alternative 4.4 No DSI-Type Reserves

4.4.1 Description of Alternative. This alternative looks at the effects of eliminating the planning and operating reserves currently provided by the DSIs under the DSI Power Sales Contracts. Unlike alternative 4.3 above, the First Quartile remains interruptible in this alternative.

Firm service is assumed for three quartiles of DSI load for both resource planning and operational purposes. The First Quartile will be served with nonfirm, surplus firm, or shifted FELCC, but with no right to interrupt the First Quartile in event of a forced outage or for system stability.

4.4.2 No Action Alternative. BPA's contractual right to restrict the DSI load under certain conditions, as specified in section 7 of the DSI Power Sales Contract, provides the Federal system with planning and operating reserves. For example, when a series of events triggered a Northwest power grid outage on October 2, 1984, six aluminum plants were the first loads cut, helping to minimize the effect of the outage on utilities and their customers. These reserves are categorized as follows:

1. Forced Outage Reserves. BPA has the right to restrict the DSI load when "a forced outage suspends, interrupts, interferes with, or curtails the operation of the Federal System Facilities" [DSI Contract, section 7(b)]. To alleviate a short-term outage, BPA can restrict the entire DSI load for up to 15 minutes. BPA may restrict up to 50 percent of the DSI load for up to 2 hours each day during the peak hours.

2. Plant Delay Reserves. In the event BPA is unable to meet its other firm obligations because of construction delay in either generating or conservation resources, or poor performance of new and existing resources, BPA may restrict the DSI Second Quartile. Second Quartile reserves are planning reserves to be used when planned resources fail to become available at the times and in the amounts planned [DSI Contract, section 7(d)].

3. Stability Reserves. The DSI load may be restricted to prevent instability on the Federal system, or on any system which could affect the Federal system, due to underfrequency on the electrical grid. BPA may restrict the entire DSI load for up to 15 minutes or 50 percent of the DSI load for up to 2 hours [DSI Contract, section 7(b].

Rates for the DSIs are adjusted to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail services to such direct service industrial customers (Northwest Power Act, section 7(c)(3)).

In determining the reserve benefits resulting from BPA's contractual rights to restrict the DSI load, each of the reserve categories listed above is separately valued at the cost to BPA of providing those reserves through alternative means. The value of power system reserves also takes into account the costs to the DSIs of a power outage. The actual amount of the value of reserves credit to the DSIs is calculated using a share-the-savings approach. The sum of the alternative cost of providing system reserves and the outage costs to the DSIs is divided by two. This approach results in an equitable sharing of the costs to the DSI when restricted and the benefits to BPA's firm power customers (including the firm portion of DSI load) in not building standby generating resources. The share-the-savings approach has the effect of giving the DSIs approximately one-half of the total cost of the reserves and saving BPA's firm power customers (including DSIs) approximately one-half of the cost of acquiring alternative means for providing the reserves.

The analysis using the methodology described above for determining the value of DSI reserves was first performed in BPA's 1982 rate filing. The analysis performed in BPA's 1982 rates was repeated for all DSI rates through BPA's 1985 rates. In each of these rates, the level of the value of the DSIs' reserves remained fairly constant in normal terms. In the 1987 rate filing, BPA adopted the IP/PF Link, which incorporates, by means of a predetermined formula, the results of the 1985 value of reserves analysis in the DSIs' rates in effect on or before June 1990. One of the reasons BPA has adopted the predetermined formula is that the value of reserves analysis was expected to continue to produce stable results absent significant changes in DSI load or resource acquisitions. (The IP/PF Link was considered in the DSI Options Study EIS. See Final Environmental Impact Statement, Direct Service Industry Options, April 1986, p. 114-115, 122. BPA has proposed extending the IP/PF link through September 30, 1995.)

CATEGORY 5: INDUSTRIAL LOAD CONSTRAINTS ALTERNATIVES

These alternatives cover issues involving contractual terms governing the size and growth of industrial firm loads. The two most important areas are: first, DSI contract provisions regarding DSI load size; and second, Utility Power Sales Contract provisions regarding New Large Single Loads (NLSL). The issues that have been grouped into this category are diverse. The one feature they have in common is that they all concern the outer limits of electric power service to industrial loads. They have been grouped together because the analysis of the alternatives of increasing DSI load and increasing NLSL growth would involve study of the same type of increased industry presence in the region.

OVERVIEW OF DSI FIRM LOAD SIZE ISSUES

There are a number of contract provisions that control DSI firm load size in various ways. The Northwest Power Act provided for the amount of power to be sold to each DSI to be equivalent to its entitlement under the pre-Act contract, subject to completion of the Council's Plan and the making of certain findings with respect to the need for additional reserves and consistency with the Plan.

The following alternatives are intended to bracket some extremes of DSI firm load size.

Alternative 5.1 Larger DSI Firm Load

5.1.1 Description of Alternative. This alternative would assume that the contracts are modified so that total DSI Contract Demand for which BPA must acquire resources would tend to be larger than the Base Case. This alternative does not assume a change in the Northwest Power Act limitation on the initial amount of power offered to the DSIs in the post-Act Power Sales Contracts. This alternative assumes assignment or transfer of current unused DSI Contract Demand. The amount of activity in transfers of unused DSI Contract Demand is, to some extent, a function of the types of assignments that would be approved by BPA. At one extreme, it could be assumed that BPA approved assignments to any entity which could perform the contract obligations of a DSI. At the other hypothetical extreme, included within Alternative 5.2 below, it could be assumed that BPA approved no assignments.

Between those two extremes is a continuum of potential criteria for approval of assignments which could increase or decrease the marketability of DSI Contract Demand and result in DSI load size between the endpoints set by Alternative 5.1 and 5.2. For example:

(a) BPA could approve assignments only from one DSI to another already-existing DSI customer or to a successor in interest;

(b) BPA could approve assignments only to assignees which engaged in the same type of industrial production at the same site as the original DSI customer;

(c) BPA could approve assignments only to nonaluminum assignees to further diversify its DSI load;

(d) BPA could approve any assignment which was expected to have a net positive effect of BPA revenues.

These examples demonstrate that there are many decision factors that could be applied by BPA: rate and revenue effects, industrial diversity in the DSI customer class, continuation of pre-existing contractual relationships, maintaining economic viability of existing DSI customers, support for local economic expansion, or best opportunity price for firm power, to name a few.

It also assumes that Contract Demand reduction due to BPA's Con/Mod program is available for transfer. (This is not allowed under the Base Case.) The alternative assumes greater use of technological increases than under the Base Case. Under this alternative, by 2001, DSI Contract Demand would grow to the highest DSI load that could be supported under the Northwest Power Act.

There would be no change assumed in the existing provisions requiring BPA to secure resources to serve DSIs after current contracts expire. BPA's resource obligation for post-contract years and quality of service are the same as expressed in the existing contracts but would be applied to a higher level of Contract Demand than the Base Case. DSI contracts are assumed to be renewed in kind in 2001.

5.1.2 No Action Alternative. Under the No Action Alternative, for purposes of analysis we will assume only such assignments of Contract Demand as have been approved by BPA at the time this analysis was performed. Under the existing contracts, some future assignments of contract may be approved.

The DSI Power Sales Contracts do not explicitly address principles for assignment of Contract Demand. GCP 39 deals with assignment of contract. It gives advance consent to security-type assignments and provides for other assignments by mutual consent between the contract holder and BPA. BPA has determined it will approve assignments of DSI contracts where the contract is assigned to a successor-in-interest. BPA will not agree to the assignment of DSI contracts to other types of parties without a public process in the region to address the controversial issues involved in nonsuccessor assignments.

The No Action Alternative allows for limited Technological Allowances which are increases in demand for the purpose of plant technical improvements or modifications. "Wheel-turning loads" (plant load not integral to the industrial process) may be served by local utilities, which may or may not include it in their purchases from BPA.

Alternative 5.2 Smaller DSI Firm Load

5.2.1 Description of Alternative. This alternative would assume that the contracts are modified such that the total DSI firm load would tend to decrease over time. This would reduce the size of BPA's commitment to acquire resources to serve DSI loads. The analysis would assume that BPA does not plan to serve DSI load after contract expiration dates. No new transfers or assignments of current unused Contract Demand would be assumed, so that a DSI plant closure or termination of a DSI contract would permanently reduce BPA's DSI obligations. The alternative would also assume that the contracts prohibit technological increases and BPA service to DSI wheel-turning load.

The analysis examines two post-contract cases which will parallel the two cases being examined for Alternative 3.5, except that the change would occur in 2001 rather than 1991. We will assume 75-percent firm service to the DSIs from the utilities and a typical utility industrial rate, discounted for the interruptibility.

5.2.2 No Action Alternative. Same as Alternative 5.1.

OVERVIEW OF NLSL ISSUES

Alternatives 5.3 and 5.4 employ opposite assumptions regarding the rates applicable to increases in industrial load. Both extremes are inconsistent with the provisions of the Northwest Power Act, but they provide contrasting endpoints for study which will bracket the effects of changes in contract provisions or contract administration policy.

A NLSL is a load at a facility that increases by 10 aMW or more in any consecutive 12-month period. The NLSL provisions of the Northwest Power Act have several purposes, including:

(1) to provide that NLSLs of preference customers are charged a rate other than the PF rate. (These "other" rates are covered by section 7(f) of the Northwest Power Act.)

(2) to constrain the access of new loads to the FBS resources thereby delaying the day when FBS replacements or additions must be made;

(3) to provide that new large loads pay the costs of the resources used to serve them;

(4) to balance the competitive posture of IOUs with that of preference customers whose wholesale power costs were expected, at the time of passage of the Northwest Power Act, to be relatively low compared to Pacific Northwest IOUs and utilities outside the Pacific Northwest; and

(5) to exclude the costs of NLSL from utility Average System Costs.

Clearly, these purposes are more appropriate in a scenario of adequate regional economic viability and competition for resources than they are in a period of declined regional economic activity and surplus resources.

By 1985, many Pacific Northwest utilities and regional industries began viewing the NLSL provision as out of touch with the current reality of surplus, and particularly harmful to a region struggling for economic recovery. Also, it appeared that the preference customer-IOU competitive balance was affected by IOU flexibility to set special rates for some industrial customers. Customers asked BPA to begin seeking lawful and contractually permissible ways to serve new large loads without incurring adverse consequences.

BPA staff proposed the use of a combination of surplus firm power and nonfirm energy to complement the contractually permitted "phasing in" of PF power service to a load in 9.9 aMW annual increments (SP/NF Phase-In). This SP/NF Phase-In concept was not adopted by BPA, but it was discussed with interested parties, and received mixed reviews. Parties favoring it pointed out that it might help BPA dispose of a portion of its surplus and help stimulate regional economic development. Parties who opposed this approach believed it would result in unfair competition between public and private utilities and foster load shifting between utilities.

Later, BPA proposed in its 1987 publication "The Bonneville Partnership: A Proposal," to develop a comprehensive NLSL policy.

Alternatives 5.3 and 5.4 bracket the extreme endpoints of the range of possible NLSL policy.

Alternative 5.3 Remove NLSL Constraints

This alternative and Alternative 5.4 below address the implications of non-DSI industrial load development in the Pacific Northwest.

5.3.1 Description of Alternative. Under this alternative, all terms of the existing contracts relating to service to NLSLs would be assumed to be modified so as to create no disincentive to the addition of new industrial load to the region. This entails assuming the removal of the linchpin of the NLSL concept, i.e., the separation of NLSLs from other firm requirements load of preference customers for rate purposes. New loads of preference customer utilities would have the same right as existing preference loads to service from FBS resources under the PF rate. This scenario requires an assumption that Northwest Power Act provisions regarding NLSL were amended by Congress, and that the Utility Power Sales Contract provisions and the Average System Cost methodology were altered. This analysis of a maximum case is intended to bracket the effects of the less extreme policy options listed in the Overview.

5.3.2 No Action Alternative. Existing NLSL contract provisions require a great deal of case-specific interpretation. The Utility Power Sales Contract contains many details not specified in the Northwest Power Act but intended to further its purpose. In applying these provisions, BPA has developed a number of practices for interpreting the Power Sales Contracts in light of actual fact situations to determine if a load is NLSL or not. These practices were described in BPA's letter to interested parties dated May 23, 1986.

CONTRACTED FOR/COMMITTED TO DETERMINATION

A new load of 10 aMW or more may be served with power purchased by a preference customer at the preference rate if it was "contracted for, or committed to" (CF/CT) by the utility prior to September 1, 1979. CF/CT status assures the load a base level of service determined by BPA at the preference rate for the life of the facility. Any increase in load above the CF/CT level which equals or exceeds 10 aMW in any consecutive 12-month period as compared to the previous 12-month period becomes an NLSL for that portion of the load and is to be served at the new resource rate. Once this occurs, any subsequent increment of load is also included in the NLSL to be served at the new resource rate (Section 8(b), Utility Power Sales Contract; Section 3(13)(B), Act).

FACILITY DETERMINATION

If a preference customer's load increases by 10 aMW or more during the prescribed 12-month period, the new load may be served with power purchased at the preference rate if the new load consists of two or more distinct loads of less than 10 average MW. The following criteria must be considered:

- separate ownership;
- separate locations;
- each load serves a manufacturing process which produces a single product or type of product;
- the loads are independent of one another;
- separate metering;
- the loads are contracted for, served, and customarily billed as separate loads; and
- the loads are treated consistently with other loads in similar situations (Section 8(a), Utility Power Sales Contract).

PHASED-IN LOAD

A load can be served with power purchased by a preference customer at the preference rate if the increase in load in any consecutive 12-month period does not reach 10 aMW as compared to the previous 12-month period. Any increase of 10 aMW or more occurring in any consecutive 12-month period causes the load to become an NLSL; the increase and any future increases are to be served at the new resource rate (Section 8(b), Utility Power Sales Contract). The date that the 12-month period begins to toll is determined as described under "Start-Up Date," below.

STARTUP DATE

Unless the load has received CF/CT determination establishing the size of load as of September 1, 1979, a utility may propose use of two alternative dates for a new load.

Either the date of initial energization of a facility (for testing or startup) or the date of commencement of commercial operation may be selected, with BPA's concurrence, to define the start of the consecutive 12-month periods. Depending on the anticipated first-year usage pattern of the load, selection of one date over the other may enable a load to receive power purchased by a preference customer at the preference rate (Section 8(d), Utility Power Sales Contract).

RESOURCE DEDICATION

An NLSL need not be served with power purchased from BPA. All or a portion of a customer-owned resource which is not included in the utility's Firm Resources Exhibit (FRE) in its Power Sales Contract or which has been withdrawn from the FRE may be dedicated to serving an NLSL. However, if the resource cannot supply the total requirements of the NLSL, BPA may serve the difference at the new resource rate, if the servicing utility gives BPA appropriate notice.

In addition, the consumer (owner of the facility) may provide on-site cogeneration or renewable resource to serve its load. As long as that resource is applied to the load, BPA will serve the remaining portion at the PF rate if it is under 10 aMW. If the resource is withdrawn, the entire load becomes an NLSL and is served at the NR rate.

CHANGE IN UTILITY

A load is not an NLSL if it moves from one location to another within the serving utility's service territory. A load which changes utilities becomes an NLSL if its energy consumption during the first 12-month period commencing on the date it becomes served by the new utility is 10 aMW or more (Section 8(b), Utility Power Sales Contract).

The No Action Alternative also includes BPA's recent modification to its SL-87 rate schedule, making this rate available for temporary service to NLSLs. BPA has not yet determined that it will offer contracts under this rate schedule or the terms of those contracts. Generally, surplus power will be available from December 1988 through September 1990. Once the SL power sale is terminated, the load will revert to usual NLSL status and will be subject to the new resources rate.

Alternative 5.4 Increase NLSL Constraints

5.4.1 Description of Alternative. This alternative would constrain NLSL growth relative to the No Action Alternative. Under this alternative, we assume that constraints on NLSLs are made more stringent by applying the NLSL designation and rate to all new industrial load growth served by Pacific Northwest Power Sales Contract customers. This would eliminate the exceptions to being an NLSL in the existing contracts, the most important being size (10 aMW), and service to the load with a dedicated resource.

5.4.2 **No Action Alternative**. Same as Alternative 5.3.

CHAPTER 3 Affected Environment

CHAPTER 3

AFFECTED ENVIRONMENT

3.1 Introduction

The study area for the proposed action includes BPA's service area (Figure III-1) covering the States of Washington, Oregon, and Idaho; the portion of Montana west of the Continental Divide; and small portions of Wyoming, Utah, Nevada, and Northern California. It also includes areas in Montana, Nevada, and Wyoming surrounding coal plants that serve the Pacific Northwest.

The NEPA requires a description of the environment in which the proposed action would take place. This chapter discusses the resources and other variables throughout the study area or parts of the area. These resources may be affected, to differing degrees, by the proposal and the alternatives.

This chapter first examines social and economic considerations in the regions that make up the study area. Topics discussed include geography and land uses, population, industry, available power resources, the demand for power, electricity rates, irrigation and recreational uses of the river systems, and existing cultural resources. The chapter then describes the natural resources environment of the study area, focusing on air quality, water quality, fish and wildlife, and vegetation. Appendix E contains supplemental data on the topics covered in this chapter.

3.2 Social and Economic Considerations

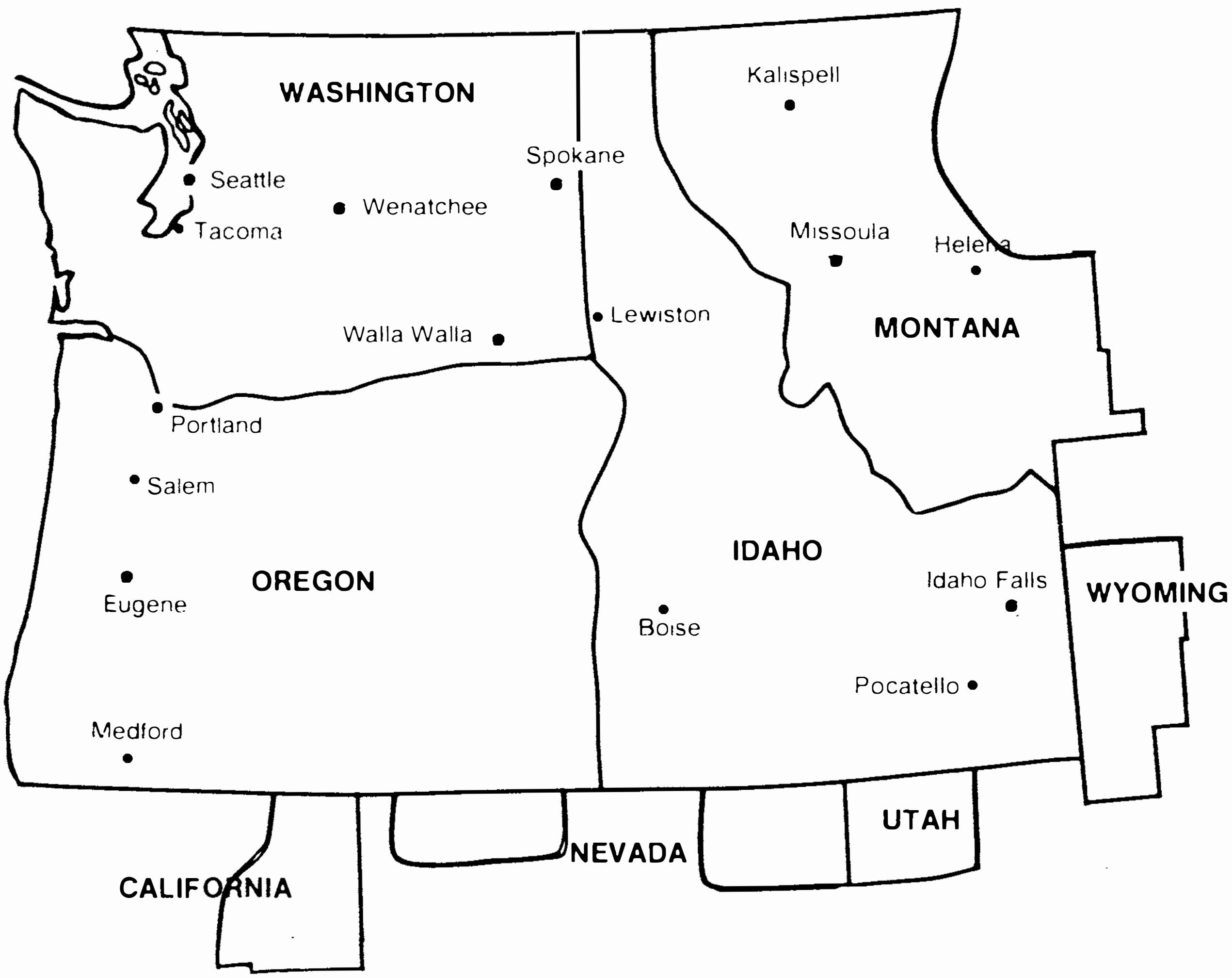
3.2.1 Geography and Land Uses

The geography and land uses of the affected environment in the Pacific Northwest center on the Columbia-Snake River system. The Columbia River Basin includes more than 258,000 square miles of drainage, including most of Washington, Oregon, and Idaho; Montana west of the Rocky Mountains; small areas of Wyoming, Utah, and Nevada; and southeastern British Columbia.

The Pacific Northwest may be divided geographically into several subregions--the Columbia River and Snake River Plateaus and four regions of valley/plains (including the Puget Sound-Willamette Valley) separated by the Coast Range, the Cascades, and the Rocky Mountains. Half of the region is covered by forest (primarily Douglas fir), most densely west of the Cascade Range. Rangeland occupies substantial areas in the Snake River and Rocky Mountain regions. Agricultural lands are located primarily on the Columbia River Plateau, along the Snake River, and in the Willamette Valley. About two-thirds of the land in the region is publicly owned and managed, enabling the development of land management programs and extensive recreational opportunities. Land managers include the Federal government (including the U.S. Forest Service, Bureau of Land Management, Department of Energy, and Department of Defense) and State and local governments. The rest of the land is privately owned.

Figure III-1

BPA SERVICE AREA



The Snake River begins in Wyoming. It flows west and north, forming part of the borders between Oregon and Idaho and between Idaho and Washington. Part of that border is the nation's deepest canyon (Hell's Canyon).

The Columbia River begins in the Province of British Columbia, Canada, and flows 1,210 miles to the Pacific Ocean. In southern Washington, the Snake River joins the Columbia and they flow west, forming the border between Oregon and Washington. The rivers flow through extensive wilderness, scenic, and recreation areas in the north and east. The rivers pass through irrigated agricultural areas in the plateau lands east of the Cascade Mountains and through the Cascade and Coast Mountain Ranges on their way to the Pacific Ocean.

The large size and drop in elevation of the two rivers once created spectacular falls and annual flooding as snow melted in the mountains. However, over the last 50 years, the Snake and Columbia rivers have been dammed to control flooding, provide irrigation, improve navigation, and produce electricity.

The locations of Federal and non-Federal Columbia Basin hydroelectric projects are provided in Figure III-2. A complete list of the general specifications of Federal Columbia River Power System dams is found in Appendix E, Table E.1.

Federal hydro projects on the Snake and Columbia River systems are operated to provide for multiple uses including power production, irrigation, navigation, flood control, recreation, fisheries, and wildlife. These sometimes competing interests are considered by the project owners and operators (the Corps and the BOR), who develop project operating constraints, stringent annual planning criteria, and shorter-term constraints as needed. Flood control constraints vary by project and are adjusted by the Corps based on projected runoff volumes. Flood control and navigation requirements are not violated except in emergencies. Special short-term requirements also may be imposed as necessary by the project owner/operator.

3.2.2 Population

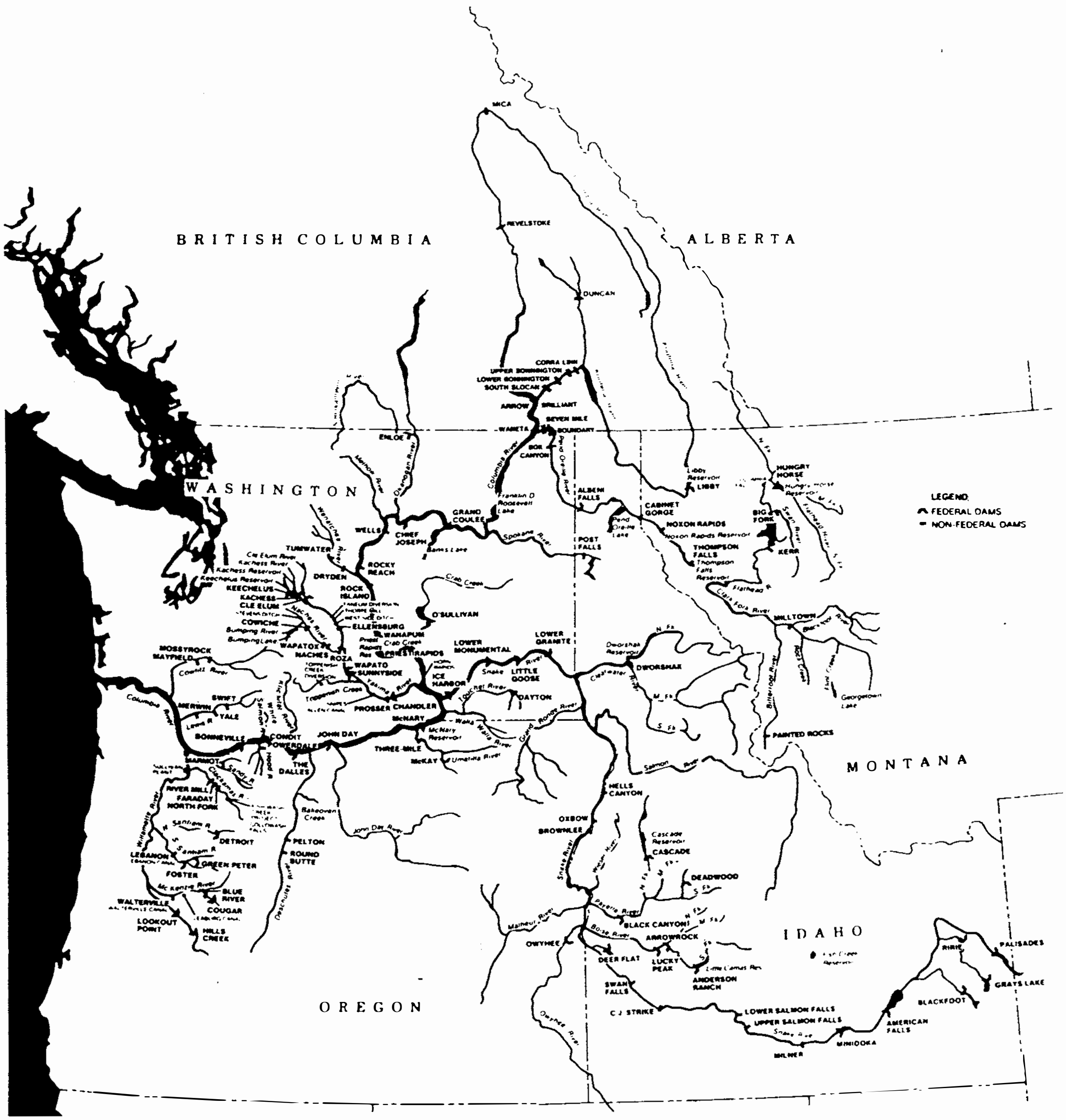
Pacific Northwest population is centered around Seattle/Tacoma (WA), Portland/Vancouver (OR/WA), Eugene/Springfield (OR), Spokane (WA), and Boise/Nampa/Caldwell (ID).

Washington population has grown from 4.13 million in 1980 to an estimated 4.80 million in 1990, a 16 percent increase (U.S. Department of Commerce, Bureau of Census). The population of Oregon (1980-90) has increased from about 2.63 million to 2.90 million, an increase of 10 percent (U.S. Department of Commerce, Bureau of Census). Idaho population has grown from 944 thousand in 1980 to 1.03 million in 1990, a 9 percent increase (U.S. Department of Commerce, Bureau of Census).

Population affects load growth (see 3.2.5, Demand for Power). It is also relevant for evaluating the significance of changes in air quality (see 3.3.1, Recreation).

Figure III-2

Columbia River Basin Hydroelectric Projects



3.2.3 Industry/Economic Base

Much of the industrial manufacturing base of the Pacific Northwest is oriented to the natural resources of the region. Extensive forests, farmland, and the oceans and rivers provide inputs to lumber and wood products, paper, and food processing industries. These industries, as well as chemicals and aluminum production, rely heavily on the historically inexpensive hydroelectric power produced in the Region.

High technology manufacturing, such as electronic equipment and aerospace, are also important, but in terms of employment, the economy is dominated by service sectors such as communication, utilities, trade, financial services, and government.

Aluminum, pulp and paper, and chemicals manufacturing are first, second, and third in industrial electricity use. The wood products and food processing industries are not electricity-intensive, but are major users of electric energy. Irrigated agriculture which withdraws water from the Columbia River system, irrigation, is essential to production of many crops in the region, particularly in southern Idaho and in central Washington and Oregon.

The Columbia River system is home to a large number of anadromous fish stocks which support economically substantial sport and commercial fisheries. Fish also are of cultural and religious value to Columbia River Basin Indian Tribes.

The river system also provides economically important recreational opportunities such as boating, swimming, fishing, and windsurfing. Scenic areas, including the nationally valued Columbia River Gorge and Hell's Canyon, attract tourists to the region.

The Columbia and Lower Snake rivers support the economy of the region by providing ship and barge transportation of crop products downriver and of goods upriver to the interior of the region.

Based on manufacturing industries and on a healthy service sector, the economy of the region has recovered from the economic recession of the early 1980s. Output of goods and services has exceeded pre-recession levels and employment has rebounded in most industries. Employment will not likely reach pre-1980 levels in some industries because of labor and other efficiencies adopted during the recession. In late 1988 and early 1989, unemployment rates in Pacific Northwest states reached record low levels.

A ninefold increase in the cost of electricity to the aluminum industry between 1979 and 1983 (in response to increased cost of BPA power and implementation of provisions of the Northwest Power Act) and low aluminum prices contributed to plant shutdowns and layoffs of workers (BPA 1983 Power Rate EIS). Plant operation tends to fluctuate with aluminum market prices.

3.2.4 Power Resources/Resource Mix

Hydropower produces about two-thirds of the total electricity used by the Pacific Northwest. There are 58 major hydroelectric dams, including 31 federally owned dams, with a combined capacity of 22,000 MW. Few sites remain in the Pacific Northwest that could effectively accommodate additional major hydroelectric development.

In the Pacific Northwest, the Wild and Scenic Rivers Act of 1968 included as part of its system the Rogue River in Oregon and the Middle Forks of the Salmon and Clearwater Rivers in Idaho. The Act established guidelines for protection of certain rivers and sections of rivers that are free flowing and that possess outstandingly remarkable scenic, recreational, geologic, fish and wildlife, historic, cultural, or other similar values.

Additional rivers have been added over time. The Oregon Omnibus National Wild and Scenic Rivers Act of 1988 added portions of 40 Oregon rivers to the national wild and scenic rivers system and mandated studies for seven others. In addition, in November 1988 Oregon's Rivers Initiative (Ballot Measure 7) added portions of 11 rivers to Oregon's existing State scenic waterways program.

As described in the Northwest Power Planning Council's Columbia River Basin Fish and Wildlife Program, BPA funded an 18-month study of certain streams deemed critical for fish and wildlife. The study examined the hydroelectric potential of such streams and the value of their fish and wildlife habitat. Based on BPA's Pacific Northwest Rivers Study and the Council's Anadromous Fish Study, the Council designated portions of stream reaches and wildlife habitat in the region that should be protected from new hydroelectric development (Protected Areas). Data from these studies and the cooperative Pacific Northwest Hydropower Data Base and Analysis System (compiled with assistance from the Corps) is being maintained by BPA and the Council as the Northwest Environmental Data Base (NED). BPA used the NED to designate Protected Areas in BPA's Long-Term Intertie Access Policy (LTIAP), issued in May 1988. The goal of Protected Areas in the LTIAP was to protect BPA's investments made to protect, mitigate, and enhance fish and wildlife. The LTIAP's Protected Areas were limited to the Columbia River Basin. The LTIAP prohibits access to the Intertie for new hydro resources built in Protected Areas.

The amount of streamflow varies from month-to-month and from year-to-year according to weather and other natural conditions. In years of heavy runoff, water is readily available to produce electricity needed in the Pacific Northwest; when streamflow is down, water stored behind certain dams, known as storage projects, is released to provide additional flow. In an average year, 16,400 aMW of hydro power is produced; in a very low water year, both streamflow and storage may be reduced and only about 12,300 aMW may be produced. In the United States, major Federal storage reservoirs exist behind the following dams: Grand Coulee (Columbia River), Albeni Falls (Pend-Oreille River), Hungry Horse (Flathead River), Dworshak (Snake River), Libby (Kootenai River). Major U.S. non-Federal storage reservoirs include the following:

Swift (Lewis River), Yale (Lewis River), Merwin (Lewis River), Round Butte (Deschutes River), Mayfield (Cowlitz River), Mossyrock (Cowlitz River), Ross (Skagit River). Three Canadian dams (Mica, Keenleyside and Duncan) also provide substantial water storage, some of which is available for use for the U.S. under the U.S.-Canada Treaty.

As described in Chapter 1, section 1.6, BPA, the Corps and the BOR are reviewing the management of the Columbia River. The System Operation Review and associated EIS are studying the use of the Columbia River system for hydropower and the system's many nonpower uses.

In addition to the hydroelectric system, 14 coal units, two commercial nuclear plants, and a number of other smaller resources of various kinds produce electricity for the region. (See Appendix E, Table E.2, for a listing of major Northwest thermal power plants.) Thermal power plants have higher variable costs than hydro plants. However, the ability to generate power at thermal plants does not depend upon natural conditions such as weather and water supply.

The Pacific Northwest energy resource mix also includes energy conservation. The 1980 Northwest Power Act directs BPA to give the highest priority to cost-effective energy conservation in acquiring resources to meet load. BPA's conservation programs are designed to improve the efficient use of electricity across all end-use categories (residential, commercial, industrial, and irrigated agricultural sectors). By improving end-use efficiency, energy conservation offers a means of regulating load growth and thus offsets the need for new generating resources.

BPA's energy conservation programs promote energy efficiency in two ways: (1) by means of installation of energy conservation measures (such as insulation, double glazing, and energy-efficient motors and appliances) in existing facilities and structures; and (2) by promoting the incorporation of energy-efficient features in new buildings and facilities. By encouraging energy efficiency in new buildings, load growth will be managed despite regional population and economic growth.

Achievable regional conservation potential varies according to cost. Estimates included in BPA's draft 1990 Conservation Resources Supply Document show a range of achievable regional energy conservation savings, under medium forecast loads, for the period 1992-2010 from 621 aMW at less than 10 mills/kWh (constant 1988 dollars) to 1,669 MW at less than 50 mills/kWh. These savings accrue from energy conservation efforts in the end-use categories of existing residential, new manufactured housing, appliances, water heating, new and existing commercial, irrigated agriculture, and industrial. (BPA, Conservation Resource Energy Data, June 1991.) These estimates do not include estimated energy savings accruing from implementation of Model Conservation Standards, which are estimated at between 60 and 370 aMW by 2010, but counted as a load reduction rather than optional resources for meeting load demands.

3.2.5 Demand for Power

Electric loads within the Pacific Northwest vary according to geographic location and season. The Puget Sound-Willamette Valley region, where two-thirds of the population lives, uses the largest amount of electricity, most of it in the winter for heating. In some areas east of the Cascades, the difference between winter and summer loads is less pronounced than west of the Cascades due to summertime irrigation and air conditioning loads. In some cases, summertime loads of utilities serving heavy irrigation loads actually exceed those utilities' winter loads.

Industrial users account for half of electric consumption, and residential users for one-third. Because the region's hydro-based power historically has been much less expensive than power in other regions, residential customers in the region use twice as much electricity at half the cost per kWh as the national average.

BPA serves half of the Pacific Northwest's loads. BPA markets power from the Corps and BOR dams and two nuclear plants--Washington Public Power Supply System Plant No. 2 (WNP-2) and a share of PGE's Trojan Nuclear Plant. The publicly-owned and IOUs sell the power they generate or purchase from BPA or other sources to regional end-use consumers (those who use and do not re-sell the power). BPA's authority (see Chapter 1) requires BPA to serve all requested needs within the region first and to serve public utilities and cooperatives before IOUs. Only if more power is available than is can be marketed in the region can BPA sell outside the region.

Demand forecasts in the late 1970s anticipated an energy shortage. The region built new generating resources that came on line as recently as the early 1980s. However, demand for electricity did not increase as expected. Consequently, the Pacific Northwest projected that it would have a surplus of firm energy and capacity for a number of years. This energy surplus is now exhausted due to recent load growth and firm surplus sales.

3.2.6 Electricity Rates

BPA sells wholesale electricity to publicly-owned utilities for resale to their residential, commercial, industrial, and irrigation consumers; to participating investor-owned and publicly-owned utilities in an amount equal to their residential and small farm consumer load; to DSIs (primarily aluminum smelter load--see Table 3-1); and to other regional and extra-regional customers as requested. Electricity produced at the Pacific Northwest dams has been inexpensive; thus, BPA's rates for wholesale power have traditionally been low relative to wholesale rates in the rest of the United States. Before 1979, residential electric rates rose more slowly in the Northwest than in the rest of the nation. In recent years, rates in the Northwest have risen more rapidly due to the inclusion in rates of the costs of WNP-1, -2, and -3 and programs mandated by the Northwest Power Act. The increases in BPA's average rate to its publicly-owned utility customers are:

1938-1965	--
1965	7 percent
1974	28 percent
1979	94 percent
1981	56 percent
1982	60 percent
1983	22 percent
1987	6 percent
1991 (proposed)	2 percent

About half of the retail power bill paid by a typical Pacific Northwest residential ratepayer covers the utility's costs of wholesale power from BPA. In 1985, average residential retail rates in the Pacific Northwest were estimated to be about 57 percent of the national average.

Table 3-1

BPA'S DIRECT SERVICE INDUSTRIES

Company	Plants	Product	Contract Demand (MW)
ACPC	Vancouver, WA	Conductor Products	5.0
Alcoa	Vancouver, WA 1/	Aluminum Extrusions	
	Wenatchee, WA	Primary Aluminum	360.0
	Addy, WA 2/	Magnesium & Silicon	
Carborundum 3/	Vancouver, WA	Silicon Carbide	34.0
Columbia Aluminum Co.	Goldendale, WA	Primary Aluminum	296.1
Columbia Falls Aluminum Co.	Columbia Falls, MT	Primary Aluminum	427.5
Georgia-Pacific	Bellingham, WA	Chlorine & Caustic Soda	34.4
Gilmore Steel 4/	Portland, OR	Ferroalloys	30.0
Intalco	Ferndale, WA	Primary Aluminum	468.0
Kaiser	Mead, WA	Primary Aluminum	
	Tacoma, WA	Primary Aluminum	737.5
	Trentwood, WA	Aluminum Rolling	
Nickel Joint Venture 5/	Riddle, OR	Ferronickel	120.0
Northwest Aluminum	The Dalles, OR	Primary Aluminum	174.0
Oremet	Albany, OR	Titanium	18.0
Pacific Carbide 6/	Portland, OR	Calcium Carbide	9.3
Atochem	Portland, OR	Chlorine & Caustic Soda	84.0
Port Townsend	Port Townsend, WA	Pulp & Paper	16.6
Reynolds	Longview, WA	Primary Aluminum	
	Troutdale, OR	Primary Aluminum	700.7
Vanalco	Vancouver, WA	Primary Aluminum	235.0

1/ Vanexco, a subsidiary of Alcoa that receives BPA power through Alcoa's Power Sales Contract.

2/ Northwest Alloys, Inc., a subsidiary of Alcoa that receives BPA power through Alcoa's Power Sales Contract.

3/ Plant was closed, torn down, and the site sold. Carborundum has not terminated its Power Sales Contract, and has sold its contract rights to Atochem North America.

4/ Plant is closed. Gilmore Steel bought the former Elkem ferroalloy plant in 1983, but has not reopened the plant. Gilmore originally intended to use the power at its steel plant, but instead was able to negotiate a more favorable power contract with Portland General Electric.

5/ The plant previously received power at the Special Industrial Power rate, applicable to plants using indigenous raw materials, as provided for in section 7(d)(2) of the Northwest Power Act. It was acquired on a lease/purchase by Nickel Joint Venture for production of ferrosilicon and nickel. The plant is being operated by Glenbrook Nickel Company. Service will be at the standard IP rate.

6/ Plant was closed and sold. Pacific Carbide still holds the Power Sales Contract.

3.3 Other Uses of River Systems: Recreation and Irrigation

As mentioned in Chapter 1, section 1.6.8, recreation, irrigation, and cultural resources are several of the uses of the Columbia River system that are being evaluated in detail in the SOR and EIS. Further information on these system uses may be found in documents produced for that process. Operational decisions that could affect recreation, irrigation, and cultural resources will be made after consideration of the results of the SOR/EIS.

3.3.1 Recreation

In the Pacific Northwest, Federal hydro projects provide numerous opportunities for recreation at the storage reservoirs and the areas downstream. Boating, swimming, water skiing, and fishing are typical water-related recreational activities; other recreational opportunities include camping, picnicking, sightseeing, hiking, hunting, and wind surfing. Many recreational activities are influenced by changes in reservoir elevation and downstream flows caused by operation of the power generation system.

Predictable changes in elevations or flows are more likely to occur at storage hydro projects than at run-of-river projects. Reservoirs are operated on an annual drawdown and refill cycle to maintain a balance among multiple uses--flood control, power generation, recreation, and fisheries. Reservoirs also are operated on a daily and hourly basis to meet needs for power, minimum flows, project restrictions, and other short-term requirements. These day-to-day and hourly project operations are less predictable than longer-term operations. Run-of-river projects can store little or no water and are operated on a daily and hourly basis to meet power needs and other project restrictions.

The five Federal storage reservoirs discussed below are operated seasonally. Reservoir drawdown is based on necessary flood control space and on power generation requirements. Maximum and minimum reservoir elevations are shown in Appendix E, Table E.3.

3.3.1.1 Libby Dam

Activities: Boating, fishing, camping, picnicking, swimming, hiking, sightseeing.

The reservoir behind Libby Dam (Lake Koocanusa) is a major recreation area in northwestern Montana. When it is full, the reservoir extends 42 miles into Canada. Most of the area surrounding the project at Libby Dam is administered by the Forest Service as part of the Kootenai National Forest. The Corps of Engineers and the Forest Service have constructed boat ramps, campgrounds, picnic areas, swimming beaches, and hiking trails along the lake. Except for a visitor facility and day-use area at the dam (operated by the Corps of Engineers), all recreational facilities at Libby Dam are administered by the Forest Service. Fishing is a prime recreational interest in the area. About 85 percent of the recreational use occurs during the 3-month period of July through September.

3.3.1.2 Hungry Horse Dam

Activities: Camping, fishing, boating, sightseeing, wildlife viewing.

The 34-mile-long Hungry Horse Reservoir is located on the South Fork of the Flathead River, entirely within the Flathead National Forest in Montana. The Forest Service administers recreational resources. Campgrounds are located close to the water's edge except during periods of deep reservoir drawdowns (primarily in winter). Campground facilities also serve as overflow sites for nearby Glacier National Park. The presence of grizzly bears and bald eagles in the area promotes wildlife observation and photography. The reservoir received approximately 75,000 recreational-use visits during 1987. The primary recreation season is June through August. During 1986, the Self-Guided Tour visitor count at the dam was 34,853; through October of 1987, it was 31,841 (less than 1986 due to highway construction).

3.3.1.3 Albeni Falls Dam

Activities: Swimming, boating, fishing, camping, sightseeing, picnicking, horseback riding, hunting, snow-mobiling.

Albeni Falls Dam regulates the discharge of Lake Pend Oreille, a large natural lake on the Pend Oreille River in northern Idaho. More than half of the land surrounding the lake is privately owned. The remaining shoreline is split among railroad and highway embankment, U.S. Forest Service, the Corps, and State and municipal ownership. Recreational facilities include private resorts, campgrounds, marinas, boat ramps, swimming and picnicking areas, wildlife management areas, and summer and year-around residences.

A major recreation event each year is the spring Kokanee and Kamloops fishing derby. The derby traditionally coincides with the beginning of the summer fishing season near the end of April. It attracts about 2,000 participants (Lake Pend Oreille, Idaho Club).

3.3.1.4 Grand Coulee Dam

Activities: Boating, fishing, camping, picnicking, hunting, wildlife observation. (Adjacent land in the Colville and Okanogan National Forests provides additional recreational opportunities including hiking, fishing, hunting, camping, and horseback riding.)

Grand Coulee Dam's Lake Roosevelt is a major recreation area on the Columbia River in eastern Washington State. The reservoir and its shores form the Coulee Dam National Recreation Area, which extends approximately 150 miles along the reservoir. Recreational facilities, including campgrounds, picnic and swimming areas, marinas, and boat ramps, are owned and operated by the National Park Service or a Park Service concessionaire. The National Park Service estimates that there were approximately 800,257 visits to the recreational facilities during 1986 and 1,037,131 visits through November of 1987.

3.3.1.5 Dworshak Dam

Reservoir Activities: Boating, water skiing, camping, picnicking, hiking, hunting, fishing.

Downstream Activities: Bass and steelhead fishing, float trips, swimming, picnicking.

Dworshak Dam and Reservoir are situated along the western slopes of the Bitterroot Mountain Range on the North Fork of the Clearwater River in northern Idaho. The reservoir is 54 miles long and, when full, has 184 miles of shoreline. The dam and lower part of the reservoir are within the Nez Perce Indian Reservation. The area surrounding the project is primarily forest land, including wilderness, scenic, and primitive areas. About three-quarters of the recreation activity occurs during the period June through September.

Recreational facilities along the reservoir are owned and operated by the Corps. Facilities include boat launching areas, picnicking and camping sites, and remote camping areas accessible only by boat. Because of downstream recreation uses, the reservoir draft rate and project outflow are important for recreation at this project. Project operating limits (firm constraints) have been established accordingly.

3.3.2 Irrigation

In addition to providing for flood control, power production, and recreation, hydro projects in the Columbia River Basin provide water and power for irrigation. The largest irrigation project in the Basin is the BOR Columbia Basin Project, which is authorized to provide irrigation to 1,095,000 acres. Only half of this project has been finished; it currently serves 556,000 acres. Most of the water for the Project is pumped from Grand Coulee (Lake Roosevelt) into Banks Lake, which serves as an equalizing reservoir. Because the pumps for this transfer are located at a fixed elevation in the pumping plant, low reservoir elevations in Lake Roosevelt can hinder or prevent pumping.

Approximately 2.3 million acre-feet of water is diverted annually for irrigation at Grand Coulee. Another 20,000 acre-feet annually is withdrawn from the Columbia-Snake River confluence. There is authorization for withdrawal of Columbia River water to irrigate the second half of the Columbia Basin project. The BOR currently is examining several proposals to expand or complete the Project. The maximum irrigation development alternative being considered by the BOR is scheduled for completion in 2027--well beyond the timeframe studied in this EIS. Of the proposed alternatives that occur during the timeframe of this study, the maximum impact on regional firm power (including the effects of water withdrawals and increased pumping load) would be approximately 50 to 100 MW. The issue of trade-offs between water use for irrigation and power production will be addressed in the BOR's environmental impact statement on Continued Development of the Columbia Basin Project.

3.3.3 Cultural Resources

Cultural resources are the nonrenewable evidence of human occupation or activity as reflected in any district, site, building, structure, artifact, ruin, object, work of art, architecture, or natural feature that was important in human history at the national, state, or local level. Cultural resources include sites around five storage reservoirs: Albeni Falls (Lake Pend Oreille); Dworshak; Grand Coulee (Lake Roosevelt); Hungry Horse; and Libby (Lake Koocanusa).

BPA has negotiated a "Programmatic Agreement for Compliance with the National Historic Preservation Act Regarding Federal Columbia River Power System Hydroelectric Operations" for the study and mitigation of cultural resource impacts of BPA power marketing policies and programs to the extent implemented through hydroelectric power operations. Along with BPA, the U.S. Bureau of Reclamation Pacific Northwest Region, the U.S. Army Corps of Engineers North Pacific Division, the National Park Service Pacific Northwest Region, the Advisory Council on Historic Preservation, the U.S. Forest Service Region 1, the Idaho, Montana, and Washington State Historic Preservation Officers, and three affected tribes are parties to the agreement. This Programmatic Agreement covers sites around each of the five reservoirs listed below. It will provide any necessary mitigation for impacts associated with the power sales contracts studied in this EIS.

For purposes of analysis, sites were grouped into locations within successive reservoir elevations of 10 feet. Sites are affected by movement of water into and out of bands of elevations as the reservoir is raised and lowered and by collectors or vandals attracted by artifacts exposed by erosion. A range of elevations was examined for each reservoir, based on current operating ranges:

Libby	2,287 - 2,459 feet
Hungry Horse	3,336 - 3,560 feet
Grand Coulee	1,208 - 1,290 feet
Dworshak	1,445 - 1,600 feet
Albeni Falls	2,049.7 - 2,062.5 feet *

* This project sometimes exceeds its normal operating limits. The maximum elevation encountered in BPA studies was 2,065.5 feet.

A description of known cultural resources, by reservoir, follows. Information is from Archaeological and Historical Services 1986.

3.3.3.1 Dworshak

A total of 38 cultural resource sites have been recorded within the Dworshak Reservoir pool. Of these, only five are recorded within the study elevation range. Many sites are inundated under several hundred feet of water. It is estimated that, if a survey were to be conducted along the margins of the reservoir, a substantial number of new sites probably would be recorded. Most investigations were conducted before the raising of the pool level behind the dam (Corliss and Gallagher 1971, 1972; Gaarder 1968; Swanson 1971; Swanson and Corliss 1971). These excavations have documented 8,000-plus years of human habitation within the region. Post-inundation studies have been few (e.g., Knudson et al. 1977; Thomas and Mierendorf 1985), although there are indications that the archaeological remains that have not been documented within this reservoir may be like those present at Libby Reservoir.

3.3.3.2 Hungry Horse

Little archaeological research has been conducted in the Hungry Horse Reservoir to date. Only three sites are recorded at this reservoir; two are at the reservoir margin and one is completely inundated. More research would be required to estimate the extent of archaeological remains at relevant elevation levels for this reservoir.

3.3.3.3 Grand Coulee (Lake Roosevelt)

Most survey work was conducted during the filling of the pool and, afterwards, above the 1,290-foot high water mark (Collier et al. 1942; Larrabee and Kardas 1966). Numerous other sites were found during a spring drawdown in 1967; all were recorded at or above an elevation of 1,240 feet (Chance 1967).

A total of 166 cultural resource sites within the study area and elevations have been identified along the 150 river miles of the Columbia, 30 river miles of the Spokane arm, 10 river miles of the Sanpoil arm, and 10 river miles of the Kettle arm comprising the Grand Coulee reservoir. Of these, 97 are prehistoric, 48 are historic, and 21 are both. The 48 historic sites (16 with Smithsonian numbers) were evaluated for this project. Precise locations could not always be assigned. Numerous additional sites had only approximate locations within elevations studied for this project (1,208-1,290 feet).

Most of the sites evaluated for inclusion in the National Register of Historic Places are included in the Kettle Falls Archaeological District (KFAD). This district is located at the northern end of Lake Roosevelt near the town of Kettle Falls. Nineteen sites are identified within the district, 14 containing prehistoric and historic aboriginal components and two with historic remains; the remaining sites contain both prehistoric/historic aboriginal and historic EuroAmerican components (Masten and Galm 1986).

Sites have been affected by erosion, including landslides and site displacement. Placer mining and relic collecting also have displaced or destroyed sites. Relic collecting, which removes the resource from the public domain, appears to be one of the most significant impacts to occur within the reservoir (Chance 1967). The cumulative effect is estimated to be severe. The exact condition of many sites is uncertain now; few sites have been evaluated according to National Register of Historic Places (NRHP) criteria.

Thirty-seven prehistoric and 35 historic sites are anticipated to have research potential based on the documented nature and extent of cultural deposits and features. Twenty-one of the historic sites are townsites, with multicomponent deposit potential.

3.3.3.4 Libby (Lake Koocanusa)

Cultural resources investigations since 1950 have recorded 265 prehistoric and historic cultural resources sites (post-inundation). The entire Lake Koocanusa Reservoir, including the lands to 2,659 feet elevation, has been declared eligible for listing in the NRHP as the Middle Kootenai River Archaeological District. Many of the sites were exposed during construction and operation of the dam. The most recent major cultural resources field investigations were conducted in 1981 and 1982. These investigations consisted of an intensive, systematic survey and site-testing program of selected sites above 2,342 feet elevation (lowest reservoir elevation for those years). The elevation range considered in the analyses in this EIS extends below this level. However, earlier studies identified few sites below the 2,342 foot level.

The quality of site data is very high. Sites above 2,342 feet have been evaluated thoroughly. A program outlining future investigations (including data recovery, future monitoring, and site recordation) is being implemented by the Kootenai National Forest and the Seattle District, Army Corps of Engineers. These studies will consider long-term (9000 BC to Present) trends and changes in human land use; human adaptation at the southern margin of the boreal forest; the beginnings of living in one settled place for hunter-gatherers; subsistence-related burning in the Northern Rockies; Kootenai Indian history and heritage; and historic trading and logging activities. Sites have been affected both before and after inundation, principally from logging, agriculture, excavation, wave-induced erosion, wind erosion, relic collecting, vandalism, and off-road vehicle operation.

3.3.3.5 Albeni Falls (Lake Pend Oreille)

A total of 227 sites have been recorded in the Albeni Falls Reservoir within the area potentially affected by this project. Thirty-four sites are historic; 172 are prehistoric; and 21 sites combine historic and prehistoric components. Site survey began in the 1950s and continued intermittently until 1985, when most of the reservoir was surveyed by Gough and Borenson (1985) and Miss and Hudson (1986). Most of the cultural resources recorded within the fluctuation zone of the reservoir are located on the gently sloping beaches, which generally are bordered by low (about .5 to 1 meter) eroding terraces or cut banks.

None of the sites has been submitted to the State Historic Preservation Officer (SHPO) for review or subsequently determined eligible for inclusion in the NRHP. Of the prehistoric sites recorded, 53 are judged to have research potential; the others cannot be judged due to insufficient information. Most historic sites are extremely marginal because they are isolated artifact scatters or are features lacking meaningful contexts. However, 11 of the sites appear to have a potential for important information within a meaningful historical context (Archaeological and Historical Services 1986). These sites include the Farragut Naval Base; the Pend d'Oreille City Townsite; the Ponderay Smelter; the Bayview Lime Kilns; Lake Mines; the A.C. White Sawmill/Laclede Ferry Landing; the (possible) Markam Homestead (1860s); Seneacquoteen; debris near Seneacquoteen; the Venton Townsite; and (possible) Northern Pacific Railroad construction camps. Of these, Seneacquoteen is most notable and possibly the most historically significant place in northern Idaho north of the Coeur d'Alene mines and the Cataldo Mission.

The greatest impact on these sites has been from erosion. In some instances, as much as 3 feet of the upper deposits of sites has been lost, and there is from 1 to 2 feet (or more) horizontal erosion per year in some areas. Relic hunters contribute to impacts on prehistoric resources as well. Seventy-six percent of all historic sites are located within bins 1 and 2, and therefore already are subject to considerable erosion and relic collecting under current operations. Natural deterioration nevertheless will continue to have the most significant impacts on historic sites.

3.4 Natural Resources Environment

3.4.1 Air Quality

Air quality is a concern in certain defined air basins and around certain generating plants in the study area (see Appendix E, Table E.4, for substantially affected coal-fired power plant locations and nearby populations; and Table E.5 for ambient air quality data for areas near affected plants). Air quality may be measured in terms of concentrations of pollutants of concern and the extent to which these approach the ambient air quality standards set by the U.S. Environmental Protection Agency (see Appendix E, Table E.6). Pollutants of concern in this analysis are those produced by extracting, processing, transporting, and burning coal, oil, and gas to produce electric power. Principal pollutants produced include sulphur dioxide (SO2), nitrogen oxides (NOX), and total suspended particulates (TSP). Carbon dioxide (CO2) produced by generating resources depending on combustion of fuels is also a concern, as it is a factor in worldwide warming, i.e., the "Greenhouse Effect."

In the Pacific Northwest, existing SO2 concentrations in the vicinity of plants whose operations may potentially be affected by PSC alternatives generally are low and do not exceed the Primary Standard. TSP levels, on the other hand, do reach or exceed the Primary Standard in a few cases. This is true particularly in rural areas, where dust from unpaved roads and agricultural activities enters the air in large amounts (Biosystems 1986). (See Appendix E, Table E.1.)

A related concern is acid deposition. Oxides of nitrogen and sulfur can combine in the air with water to form acid rain or snow, which may adversely affect water resources and plant and animal life. A National Acid Precipitation Assessment Program has begun to study sites for acid deposition. Western sites vulnerable to acid deposition include the Cascade Mountains of western Washington. The link between changing levels of generation and observable impacts of acid deposition is complex and difficult to quantify. It depends on many variables such as micro-climate, alkalinity of soil and water, and soil depth and composition. (Data on concentrations of components of precipitation related to acid deposition are presented in Appendix E, Table E.8.)

3.4.2 Water Quality and Fish

The study area includes a wide variety of water resources and fish species. Water resources potentially affected include groundwater supplies, rivers, streams, reservoirs, lakes, ponds, estuaries, marshes, and ocean water. Fish species include nearly the full range dwelling in such water bodies. The environmental description for these resources will be generalized by region. Characteristic species are listed in Appendix E, Table E.9.

Both of these issue areas and their relationships to other uses of the Columbia River system are discussed and evaluated in the System Operation Review and associated EIS. The goal of the SOR/EIS is to achieve a rebalancing of the competing uses of the hydro system, including power generation, navigation, irrigation, and recreation as well as water quality and fish.

3.4.2.1 The Hydroelectric System

Pacific Northwest rivers are host to numerous anadromous fish (species which migrate down the rivers to the ocean, then return upstream to spawn). To complete their journeys, they must pass as many as nine dams, which have impounded most of the free-flowing sections of the Columbia River. Fish journeying to the natural spawning areas in the Snake River and its major tributary, the Salmon River, must pass eight dams (four on the Columbia and four on the Snake). Chief Joseph Dam on the Columbia and Hells Canyon Dam on the Snake mark the upstream limits of anadromous fish migration.

The tributaries, lakes, and upper portions of the Columbia River system are the major spawning and nursery grounds for anadromous fish. The principal anadromous fish in the Columbia Basin are steelhead trout; three species of salmon (chinook, coho, and sockeye); and shad. Unlike species of the salmon family (salmonids), however, shad do not inhabit smaller tributaries but use mostly the mainstem of the Columbia and Willamette rivers. Other anadromous species include the white sturgeon, striped bass, eulachon, and Pacific lamprey.

Anadromous fish, particularly salmonids, require high-quality water. Relatively warm water, low dissolved oxygen, and nitrogen supersaturation have created the greatest water quality problems for fisheries in the Columbia River Basin. Anadromous salmonids generally do not tolerate such conditions as well as resident species, especially when such conditions develop quickly.

Anadromous fish migration, spawning, and survival of eggs and juveniles are closely linked to water temperature. Flow rates affect the travel rate of both upstream and downstream migrants. Dissolved oxygen concentrations affect the rate of development and growth of eggs, larvae, and juveniles. Effects of toxicants on juvenile salmonids have been studied extensively, and salmonids are known generally to be more sensitive to many pollutants than other groups of fish.

The Columbia River and its tributaries also contain a variety of resident fish. Resident fish spend their entire life in fresh water, although some regularly migrate fairly substantial distances within the fresh-water system. Many resident species are relatively tolerant of stressful environmental conditions such as relatively high temperature, low concentrations of dissolved oxygen, and the presence of small amounts of certain toxic pollutants.

Fish problems associated with Columbia and Snake River dams have been developing for a number of years. In many cases, mitigation for some of the expected fisheries losses was provided at the time of hydro project construction. Hatcheries were built or operational funds allocated to rear fish to replace those lost due to inundation of spawning grounds and other causes. The Northwest Power Act, on which the Council's Columbia Basin Fish and Wildlife Program is based, provides guidance to BPA to fund proposals of Federal and state agencies, Indian Tribes, and private individuals to mitigate the loss of fish and wildlife throughout the Columbia River Basin due to hydroelectric projects. These proposals include construction of hatcheries for anadromous and resident fish, improvement of fish passage facilities, fish and wildlife habitat enhancement activities, and water requirements to provide adequate flows during critical fish migration periods.

Recent proposals for listing salmon species as threatened or endangered species under the Endangered Species Act have stimulated new efforts to develop actions to enhance the survival of Columbia River salmon. Efforts to develop consensus on a strategy to restore declining runs have led to renewed exploration of activities affecting habitat, passage, and harvest in order to prevent further decline. The design of these efforts is the subject of other analyses already underway independent of this EIS.

Both anadromous and resident fish have been affected at different stages of their life cycles by the environmental changes created by the existence of hydro projects in the Columbia River system. The following discussion focuses, in turn, on downstream-migrating juvenile salmonids, upstream-migrating adult salmonids, and resident fish.

DOWNSTREAM MIGRANTS

Downstream migration is greatest during April, May, and June, historically the periods of greatest flow in the mainstem. Maintaining high flows requires increased releases at most dams, facilitating the passage of juvenile salmonids through the system. Excessive spill, however, which will occur if there are not sufficient demands for generation to consume all of the power produced by increased flows, may create high dissolved nitrogen levels (nitrogen supersaturation), which is detrimental to both downstream-migrating juveniles and upstream-migrating adults.

Downstream migrants (between 5 and 30 percent) may pass through the turbines at the dams. Turbine mortality may result directly or indirectly from injury to the fish from pressure or impact: stunned fish surviving the turbine discharge may be eaten by predators. The type of turbines, efficiency of turbine operation, presence of predator fish, time of passage, and a number of other factors are important variables in determining chances of survival through the powerhouses.

Fish also have been affected by the transformation of what was a fast-moving stream into a series of slow-moving lakes or reservoirs behind dams. Downstream migration time has slowed and has subjected downstream migrants (particularly juveniles) to considerable biological stress. Prolonged delays expose juveniles to predation and disease and can cause them to lose their time-critical ability to adapt to saltwater when they reach the ocean.

Survival of juvenile fish also can be affected by stranding. When storage reservoirs are drawn down rapidly, small fish may become isolated in the discontinuous pools formed as the water recedes. They can become easy prey for birds and animals or may die as the temperature of shallow pools increases and oxygen is depleted. Fluctuating river levels can also expose salmon redds (egg nests) allowing them to freeze or desiccate. The Vernita Bar Agreement protects redds in the Hanford Reach by regulating river flows from spawning throughout emergence on Vernita Bar.

UPSTREAM MIGRANTS

Significant otherwise unexplained losses of adult upstream migrants may be attributed to Columbia and Snake River dams. Most adult mortalities due to dams are directly or indirectly linked to delays in migration and seem to be species-related. Some fish ascend the fish ladders provided for upstream passage but allow themselves to pass back over the dam ("fallback") via the spillway. They must then reascend the ladder. Although fallback may occur to some degree at most dams, the problem is especially acute at Bonneville Dam, where fallback has been estimated at between 25 and 35 percent.

Hydropower peaking also may adversely affect upstream passage of adult salmon and steelhead. Peaking operation can cause forebay and tailwater elevation fluctuations beyond design limits of fish passage facilities at dams, which reduce the ladders' ability to attract and assist adult salmonids.

RESIDENT FISH

Resident fish tend to inhabit a particular area of a river for long periods of time (seasonally) or throughout most of their lives. Thus, the distribution and abundance of various species is affected more by local habitat conditions than by general conditions prevailing throughout the river system.

Warm water species, such as the largemouth bass, bluegill, and crappie, are particularly susceptible to reservoir fluctuations. They spawn in the spring when the water warms to about 60 degrees. Nests are constructed in sheltered shallows near the edges of the reservoirs at depths from less than 2 feet to about 10 feet. Increases in reservoir fluctuations could change water temperatures or expose nests, killing the eggs.

Resident trout are reared in hatcheries and stocked in many lakes, reservoirs, and streams throughout the Pacific Northwest. Most of the easily accessible trout waters are stocked annually because natural production cannot keep pace with demand. Rainbow trout are fairly tolerant of warm temperatures and inhabit the reservoirs and tributary streams throughout the system. Other resident fish inhabit the colder portions, seeking the mouths of cold streams, underwater springs, and cool main currents. Spawning must be accomplished in tributary streams, however, because the reservoirs, except for areas immediately below the dams, do not provide suitable spawning habitat (a gravel substrate with highly oxygenated water percolating through it).

Reservoir waters often favor the establishment and proliferation of nongame species because the new habitat is not ideally suited for establishing a dominant population of either warm- or cold-water game species. In many cases the two habitat types overlap, and warm and cold water species coexist. Reservoir environments that exist today have permitted warm water species to proliferate, although not in great abundance, while spawning populations of trout are confined to the colder tributary streams.

3.4.2.2 Thermal Plants and Water Use

Nuclear and coal-, oil-, or gas-fired generating plants use water for cooling. Water is taken from rivers, aquifers, Pacific coastal waters, and reservoirs and is recycled within the plant or returned to its source. Characteristic and important fish species in water bodies utilized by generating plants shown in the analysis to be substantially affected by PSC alternatives are listed in Appendix E, Table E.10.

The Yellowstone River in Montana, the Green River in Wyoming, the Skookumchuck River in Washington, and the Columbia River in Oregon supply water for cooling purposes to Pacific Northwest thermal plants.

The Yellowstone River supports the largest and most important recreational fishery in southeast Montana, with over 30 species of primarily warm water fish such as catfish and sturgeon in the Forsyth, Montana, area. Precipitation and runoff in the area are low. The river supplies water via pipeline to Castle Rock Reservoir, which supports a warm water fishery and provides water for the Colstrip coal plant, near Forsyth.

The Green River, near Green River, Wyoming, is regulated at Fontenelle Reservoir. It supports an important fishery for brown and rainbow trout. The river supplies water for the Bridger coal plant. The historical mean annual discharge is 1,763 cfs. Minimum discharge occurs in the winter (688 cfs in February 1984).

The Skookumchuck River, regulated by Skookumchuck Dam, supplies water to the Centralia coal plant. It is a typical Cascade Mountain stream with a full complement of resident and anadromous salmonids (chinook, coho, and chum salmon; steelhead; and cutthroat trout), which use the area near the plant for spawning.

Carty Reservoir, filled with water pumped from the Columbia River, supplies water for irrigation and for cooling the Boardman coal plant. The cooling water is discharged back to the reservoir. The reservoir supports sculpins and smallmouth bass. There is no recreational use of this reservoir.

The Columbia River also supplies cooling water to the WNP-2 nuclear plant and to the Trojan nuclear plant near Rainier, Oregon.

Groundwater from the Humboldt River Basin supplies the Valmy coal plant in Nevada. The aquifer also supplies domestic consumption and livestock (Biosystems 1986).

3.4.3 Wildlife and Vegetation

Vegetation within the Pacific Northwest falls into five general community types--forests/woodlands, shrublands, grasslands, deserts, and riparian/wetland (see Figure III-3). Each plant community has characteristic associated wildlife types. Because the diversity is so considerable, and because combinations of these communities may occur with an intermixed or "edge" effect, the following discussions will focus on plant communities and associated wildlife. Specific types will be mentioned only as typifying a group or where species are specially protected. Lists of characteristic wildlife species are found in Appendix E, Table E.11. (Information following is from Biosystems 1986.)

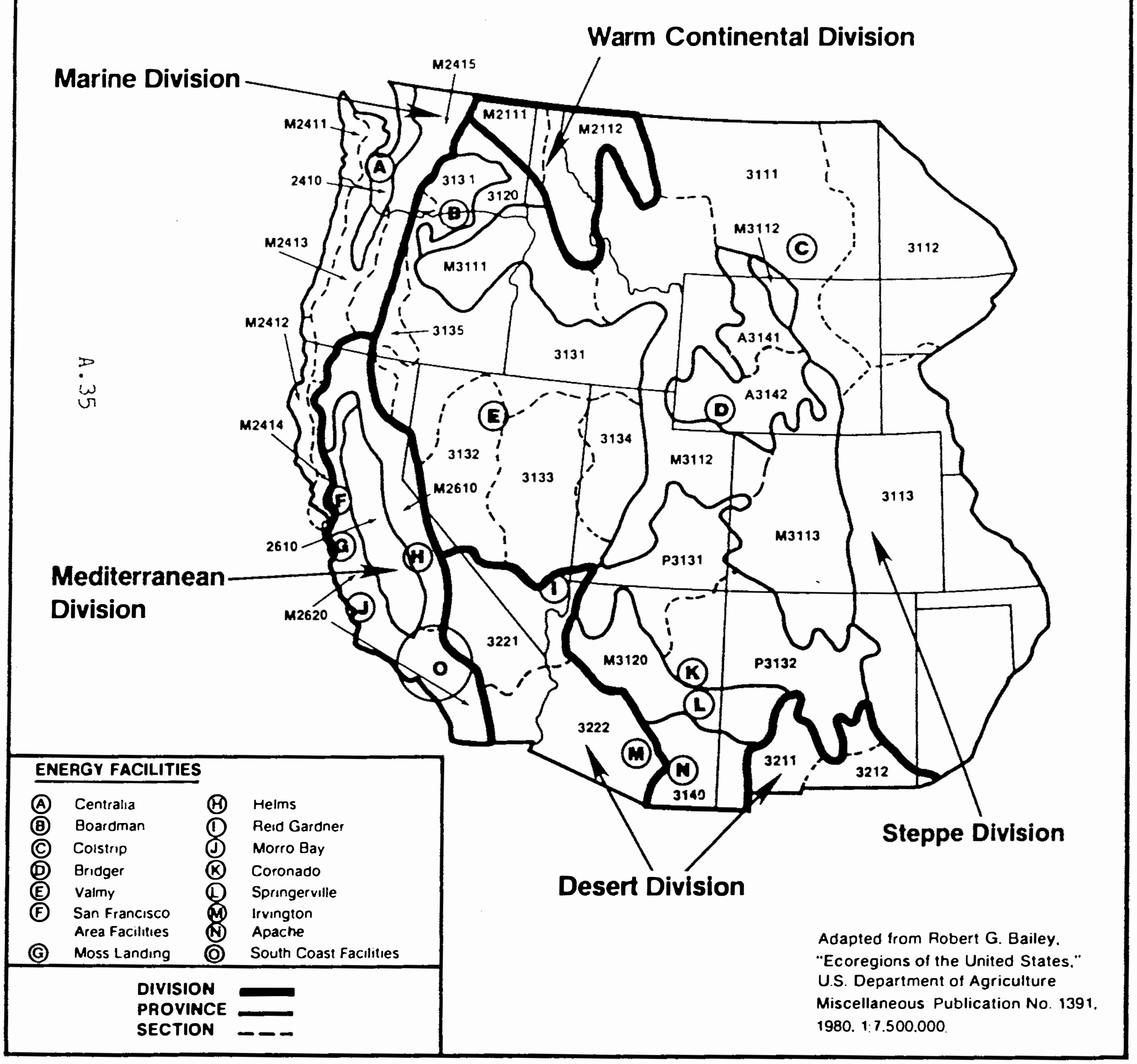
3.4.3.1 Forest/Woodland and Wildlife

The forest/woodland plant community provides many "layers" of habitat for wildlife from the ground into the upper branches of older trees. Most vulnerable to change are older stands of trees of various ages, which may take a century or more to develop and thus cannot easily or quickly be replaced.

Large and small mammals, including deer, members of the weasel and skunk family, and rodents such as squirrels and porcupine, are found in the forested areas. Any of these mammals that prefers a narrowly defined habitat can be affected by disturbance or removal of habitat. The forest community, with its many varieties of trees, houses a large number and variety of birds, depending on the region and composition of the forest.

Figure III-3

LOCATIONS OF ECOSYSTEM REGIONS AND ENERGY FACILITIES



LEGEND

MARINE DIVISION 2400

2410 Willamette-Puget Forest Province

HIGHLANDS

M2410 Pacific Forest Province
- M2411 Sitka Spruce-Cedar-Hemlock Forest Section
- M2412 Redwood Forest Section
- M2413 Cedar-Hemlock-Douglas-fir Forest Section
- M2414 California Mixed Evergreen Forest Section
- M2415 Silver Fir-Douglas-fir Forest Section

MEDITERRANEAN DIVISION 2600

2610 California Grassland Province

HIGHLANDS

M2610 Sierran Forest Province
M2620 California Chaparral Province

STEPPE DIVISION 3100

3110 Great Plains Short-grass Prairie Province
- 3111 Grama-Needlegrass-Wheatgrass Section
- 3112 Wheatgrass-Needlegrass Section
- 3113 Grama-Buffalo Grass Section

3120 Palouse Grassland Province
3130 Intermountain Sagebrush Province
- 3131 Sagebrush-Wheatgrass Section
- 3132 Lahontan Saltbrush-Greasewood Section
- 3133 Great Basin Sagebrush Section
- 3134 Bonneville Saltbrush-Greasewood Section
- 3135 Ponderosa Shrub Forest Section

3140 Mexican Highlands Shrub Steppe Province

HIGHLANDS

M3110 Rocky Mountain Forest Province
- M3111 Grand Fir-Douglas-fir Forest Section
- M3112 Douglas-fir Forest Section
- M3113 Ponderosa Pine-Douglas-fir Forest Section

M3120 Upper Gila Mts. Forest Province
P3130 Colorado Plateau Province
- P3131 Juniper-Pinyon Woodland + Sagebrush-Saltbrush Mosaic Section
- P3132 Grama-Galleta Steppe + Juniper-Pinyon Woodland Section

A3140 Wyoming Basin Province
- A3141 Wheatgrass-Needlegrass-Sagebrush Section
- A3142 Sagebrush-Wheatgrass Section

DESERT DIVISION 3200

3210 Chihuahuan Desert Province
- 3111 Grama-Tobosa Section
- 3212 Tarbush-Creosote Bush Section

3220 American Desert (Mojave-Colorado-Sonoran) Province
- 3221 Creosote Bush Section
- 3222 Creosote Bush-Bur Sage Section

WARM CONTINENTAL DIVISION

HIGHLANDS

M2110 Columbia Forest Province
- M2111 Douglas-fir Forest Section
- M2112 Cedar-Hemlock-Douglas-fir Forest Section

(M) Mountains
(P) Plateau
(A) Altiplano

3.4.3.2 Shrubland and Wildlife

Shrublands are located in areas too harsh for forests and areas subject to repeated natural disturbances such as floods or fires. They therefore may be relatively resilient to human disturbances but also may be replaced by grasslands species if they are disturbed. When shrubland communities are separated by mountain ranges, they will contain widely differing wildlife communities. They share adaptable wide-ranging species such as mule deer, coyote, gray fox, mountain lion, and a variety of birds. Each shrubland contains birds and many small mammals, and all contain the ermine, a common hunter of these mammals.

3.4.3.3 Grasslands and Wildlife

With its tremendous volume of seed-bearing but nonwoody materials, grasslands typically sustain fewer kinds of wildlife but very large numbers of individual species such as rodents (e.g., ground squirrels). These small mammals attract predators, including hawks. The predominantly grassland provinces, including the Palouse, are separated by mountain ranges. Only wide-ranging mammals such as mule deer, coyotes, and badgers occur in all. Grasslands habitat supports fewer birds than other vegetation areas because appropriate perching and nesting habitat is sparse.

3.4.3.4 Desert and Wildlife

Deserts are harsh and fragile environments in which plant growth rates are slow. Revegetation may take years or decades. The wildlife inhabiting this environment often is specialized for the harsh conditions, obtaining water from vegetation and avoiding daytime heat by being active primarily at night. Dominant carnivores are small and nocturnal. They include the coyote and spotted skunk, as well as the endangered kit fox (*Vulpes macrotis*) in some areas. Varieties of rodent (such as kangaroo rats and ground squirrels) are fairly common. Areas with cactus or brush may support a variety of birds, especially where water sources allow trees to grow.

3.4.3.5 Riparian/Wetland and Wildlife

Riparian/wetland plant communities have high vegetation and wildlife value. This discussion on riparian vegetation is not classified according to habitat type because of the great diversity along the Columbia and Snake Rivers and their tributaries. These habitat types can range from sand dunes to various types of wetlands. Deer, beaver, and other aquatic and terrestrial fur-bearers, small mammals, waterfowl, upland game birds, reptiles, and amphibians are among the common year-around users of riparian/wetland areas. Wintering elk and moose also may use these areas.

Before dams were built on the Columbia River and its tributaries, riparian vegetation zones developed through natural succession. Many plant species dependent on a high water table or periodic inundation were present. However, some areas subject to natural flooding eroded and were unable to support much vegetation. The flooding of the river valleys as dams were built destroyed much of the original riparian vegetation. In some cases, new vegetation similar to previous types has replaced original vegetation, but it has occurred higher on the shoreline to correspond with the new, higher waterline.

Changes or disturbances to water areas, wetlands, and the high-yield grain crops adjacent to wetlands, contribute to an increase or decrease in wildlife and waterfowl populations and habitat. These changes and disturbances are associated with shoreline construction, water level fluctuations, and shoreline erosion. Shoreline erosion in some areas has created unstable conditions in which vegetation cannot become established. Slides and wave action continuously remove soil and plant materials. Construction efforts to control water erosion have created miles of shoreline covered with rock riprap in which little will grow. Water level fluctuations also have prevented the riparian community from developing except near the highest pool elevation.

CHAPTER 4

Environmental Consequences

CHAPTER 4

ENVIRONMENTAL CONSEQUENCES

GENERAL ANALYTICAL METHOD

As explained in Chapter 2, the alternatives in this EIS are simplified scenarios concerning certain important contract and policy issues. Often, these simplified alternatives present extreme cases which are not necessarily realistic, but which yield pertinent environmental information despite the absence of negotiated, detailed proposals. The alternatives and analysis lack important features that would result from negotiations. These features would be studied during a Stage Two process after this EIS, if the Stage Two proposal consisted of amendments to the contracts.

These alternatives cover a wide range of potential environmental impacts ranging from more direct effects due to generating resource operations to indirect effects due to cost allocations. For each alternative, the most appropriate analytical method was selected to show the effects in the most important areas of environmental concern. In some cases, computer models were used to calculate potential impacts. (Appendix G contains more information on each of the computer models used.) In other cases, qualitative analysis was used to assess impacts that could not readily be quantified. Because of the different analytical methods used, the descriptions of environmental impacts of each alternative are organized differently, reflecting a great deal of tailor-made analysis. Subsection headings indicate the important environmental implications in each case.

For alternatives analyzed with computer models, BPA has utilized the best available models to simulate the simplified scenarios. The models are being used here to deduce environmental impacts though most of them were designed for other purposes, such as comparisons of net economic effects of various decisions. In addition, the inputs into the models and the models themselves necessarily include simplifying assumptions. The quantitative outputs of the studies have, therefore, been interpreted by qualitative judgments and expertise. Despite these caveats, the model outputs help to reflect the range of environmental consequences that could be expected.

The initial goal for the analysis for all alternatives, whether or not models are used, is to determine effects on the region's power system. Power system effects include, for example, changes in level and pattern of operation of generating resources, changes in the business obligations of various parties, differences in types and amounts of resources developed, and changes in system costs and investment. Once power system effects are determined, further qualitative or quantitative analysis is applied to assess impacts on the physical environment.

In addition, as discussed in Chapter 1, section 1.6, the Resource Program EIS and the SOR EIS include analyses designed to determine power system effects.

The Resource Program EIS evaluates options for resource development, and the SOR EIS evaluates options for resource operations to balance competing uses of the hydro system. The 1992 Flow Measures EIS addresses operations to enhance the survival of salmon runs proposed for listing as threatened or endangered. Decisions regarding these general issue areas will be made after the pertinent EIS is completed, so as to include consideration of the EIS's findings. The results of these EIS processes may establish limits on resource operations and development which are independent of the analysis presented here.

FIGURE IV-1

SUMMARY AND COMPARISON OF IMPACTS OF ALTERNATIVES

ALTERNATIVE	QUESTION/CONTROVERSY	RESULT
Category 1: Hydro Development and Operations - Contract issues that could affect hydroelectric dams.		
1.1 Fish and Wildlife Compliance as a Condition of Service	More utility actions for fish and wildlife benefit?	No significant change except possible avoidance of new dams on sensitive streams.
1.2 No Use of Borrowing Techniques for DSI First Quartile Service	Different reservoir levels or flows affecting fish, wildlife, recreation?	No significant change.
1.3 Limit Firm Load Changes Within Operating Year	Short notice changes affecting hydro operations?	No significant change for dams. More non-BPA thermal power plants built and used.
Category 2: Conservation - Contract issues that could affect electric power conservation efforts.		
2.1 Conservation Compliance as a Condition of Service	Change in incentive for utility conservation activity?	No significant change.
2.2 Conservation Transfers Facilitated	Change in overall conservation activity?	Effects variable but no significant change expected under most likely load/resource conditions.
Category 3: Resource Planning and Development - Contract issues that could affect the amounts and types of conservation programs and power plants to be developed by BPA and others.		
3.1 BPA Load Placement Certainty	Would more advance notice of customer needs change the amounts or types of conservation and power plants planned by BPA?	BPA resource obligation could increase or decrease significantly, depending on customer reaction to longer notice requirement.
3.2 BPA as Regional Supplier	If utilities left future resource responsibilities to BPA, would there be a difference in the conservation and power plants developed in the Northwest?	Probably more conservation and less coal, small hydro, or cogeneration types of power plant development.

FIGURE IV-1

SUMMARY AND COMPARISON OF IMPACTS OF ALTERNATIVES

ALTERNATIVE	QUESTION/CONTROVERSY	RESULT
3.3 Customer Planning on Other Than Critical Water Basis	Do the contracts keep utilities from changing to water planning methods that would increase the amount of power assumed to come from dams?	The contracts do not significantly affect utility decisions in this area.
3.4 Improved Ability to Exercise Provisions to Make Purchases in Lieu of Exchanges	Do the contract limitations affect development of economical conservation programs or power plants?	The contract limitations referred to could significantly affect the economics of some parties, but not resource needs or the environment.
3.5 Shorter Contract Terms	Would shorter contract terms affect development of power plants or conservation by BPA or others?	No significant change for utility customers. DSI customers likely to pursue non-BPA suppliers or self-owned power plants, reducing BPA resource needs.

Category 4: Quality of Service as a Resource Choice - Contract issues dealing with agreed-upon service interruptions which avoid need for some power plant additions.

ALTERNATIVE	QUESTION/CONTROVERSY	RESULT
4.1 Increase First Quartile-Type Interruptibility	Would this reduce the need for more conservation or power plants?	Yes. Could also significantly harm DSI customers.
4.2 No BPA Purchase Required for Certain Exercise of First Quartile Restriction Rights	What would change if direct service industrial customers were directly responsible for some additional power purchase costs?	No significant change unless the direct cost was too high for DSIs to afford, causing less production. The probability of this is unknown.
4.3 Increase Quality of Service to First Quartile	Would more resources be needed?	Dates for BPA acquisition of resources would be earlier. Alternative sources for some reserves would be needed.
4.4 No DSI-Type Reserves	Would more resources be needed?	Alternative sources for DSI reserves needed - new power plants or contractual interruption arrangements.

FIGURE IV-1

SUMMARY AND COMPARISON OF IMPACTS OF ALTERNATIVES

ALTERNATIVE	QUESTION/CONTROVERSY	RESULT
Category 5: Industrial Load Constraints - Contract issues that can encourage or discourage industrial growth.		
5.1 Larger DSI Firm Load	Change in need for resources?	Need for resources could increase significantly by 700 MW (19% over current DSI est. load) by 2001.
5.2 Smaller DSI Firm Load	Change in need for resources?	Need for resources could decrease by a small amount, approximately 7% by 2001.
5.3 Remove NLSL Constraints	Change in need for resources?	Need for resources could increase moderately by 290 MW by 2001. Likely increase in pulp & paper processing.
5.4 Increase NLSL Constraints	Change in need for resources?	Need for resources could decrease by a small amount, approximately 73-116 MW by 2001.

SUMMARY COMPARISON OF IMPACTS OF ALL ALTERNATIVES

The following is a summary comparison of the impacts of all of the alternatives analyzed in this EIS. A detailed discussion of the impacts of each alternative follows this summary section.

Each of the 18 alternatives for this EIS has been analyzed in comparison with the No Action Alternative. Most of these alternatives address different issues in the Power Sales Contracts (PSCs) and therefore are not alternatives to each other. The exceptions are in Category 4, Quality of Service as a Resource Choice, and Category 5, Industrial Load Constraints, where the alternatives attempt to bracket both extremes of the potential range of changes that could be envisioned.

CATEGORY 1: HYDRO DEVELOPMENT AND OPERATIONS ALTERNATIVES

Alternative 1.1 Fish and Wildlife Compliance as a Condition of Service

KEY AREA(S):

Fish and wildlife effects due to increases in implementation by BPA's customers of the Northwest Power Planning Council's (Council) Fish and Wildlife Program (Program) measures.

RESULTS:

The alternative is not likely to significantly affect the implementation of Program measures aimed at the fishery impacts of existing hydro resources. The alternative might increase the likelihood of implementation of Council measures directed at new hydro resources, namely, the Protected Areas rule. The Council's wildlife measures do not require customer implementation.

Alternative 1.2 No Use of Borrowing Techniques for DSI First Quartile Service

KEY AREA(S):

Effects on hydro operations of use of borrowing techniques (such as Firm Energy Load Carrying Capability (FELCC) Shift, Flexibility, or Advance Energy) for the DSI first quartile.

RESULTS:

No significant environmental effects due to changed resource operations are expected. A small change in the seasonal shaping of FELCC could be expected, but it would be insignificant, since the coordinated system would continue to use FELCC Shift to the greatest extent possible to supply other loads and surplus marketing. There would be a potential for reduced DSI load due to reduced quality of service, including potential closure of existing aluminum smelters. This could reduce the need for new resources and have other effects associated with loss of DSI economic viability, such as loss of DSI reserves and the concomitant need for replacement reserves, and economic effects on localities surrounding those DSI plants which might close. (See Chapter 4 and Appendix A of the Final EIS on Direct Service Industry Options, DOE/EIS-0123F, April 1986.)

Alternative 1.3 Limit Firm Load Changes Within Operating Year

KEY AREA(S):

Effects on resource operations due to rights under the existing PSCs for customers to change amounts of firm load to be served by BPA within an operating year.

RESULTS:

The alternative shifts from BPA to customers some of the obligation to respond to end-user load changes. The change in obligation would tend to increase customer use of non-Federal coordinated system resources to the extent possible. It also could increase the development of non-Federal resources to back up utility systems or DSIs against load contingencies. The shift to operational reliance on non-Federal resources could result in presently unquantifiable environmental impacts due to increased use of existing non-Federal resources (primarily large thermal generators or combustion turbines), to the extent that utility least-cost resource plans deviate from BPA's resource stack. The increased development of non-Federal resources would have environmental impacts similar to those discussed for Alternative 3.2 below.

CATEGORY 2: CONSERVATION ALTERNATIVES

Alternative 2.1 Conservation Compliance as a Condition of Service

KEY AREA(S):

Change in amount of conservation developed in BPA customer service areas.

RESULTS:

No change is expected in the amount of conservation in BPA's service area, due to the projected continuation of participation by preference customers in BPA programs, consistent with least-cost planning. No change is expected for IOUs, either, since they are projected to acquire cost-effective conservation in accordance with least-cost planning principles. The existing Power Sales Contracts do not place conservation at a disadvantage with respect to generating resources. Existing provisions have no significant effect on economic or other policy factors effecting conservation implementation.

Alternative 2.2 Conservation Transfers Facilitated

KEY AREA(S):

Change in amount of conservation in the Pacific Northwest due to conservation transfers.

RESULTS:

Removing the prohibition against resale of Federal firm requirements power could increase the "marketability" of some conservation transfers by an unquantifiable amount. However, the amount of regional conservation gained by conservation transfers is highly uncertain, depending on load/resource balance and the amount of conservation captured by BPA. Removal of the prohibition against wholesale resale of Federal firm requirements power would have adverse public policy results with respect to preference customer rights to the Priority Firm (PF) Power rate and Federal base system resources. It also would be inconsistent with the statutory 5-year cancellation provision for BPA contracts with IOUs.

CATEGORY 3: RESOURCE PLANNING AND DEVELOPMENT ALTERNATIVES

Alternative 3.1 BPA Load Placement Certainty

KEY AREA(S):

Resource planning effects of increased uncertainty of load placement on BPA--a 10-year certainty period compared to the 7-year certainty period under the existing PSCs.

RESULTS:

Analysis showed that the effect of 10-year certainty is uncertain, depending on customer response to the added risk of a 10-year commitment versus a 7-year commitment. The longer notice could decrease overall load placement on BPA if customers chose more flexible resource planning strategies. If customers did not so choose, a 10-year period would not significantly change the types of resources BPA would develop initially. In some scenarios, the extra notice could increase the chance that BPA could decide to complete Washington Public Power Supply System Nuclear Plants (WNP)-1 and -3 or develop other large thermal plants.

Alternative 3.2 BPA as Regional Supplier

KEY AREA(S):

Regional resource planning effects of current power sales contract provisions that provide that utility customers may develop their own resources.

RESULTS:

Utility rights to plan and acquire resources independently are protected by section 10(a) of the Northwest Power Act. The effects of such independent development (compared to regionally centralized resource development by BPA) were studied by BPA and the Council prior to this EIS (e.g., the 1986 Power Plan, Chapter 2). It is expected that centralized resource development by BPA would tend to result in lower net regional costs. Lower costs are a result of increased conservation and use of Federal resources such as WNP-1 and -3 and firming of Federal nonfirm energy. In contrast, utility resource development has been projected to include more renewable resources such as small hydro and cogeneration, and more coal plants, although coal plant development is expected to be deferred until after acquisition of conservation and other lower-cost resources. Recent utility plans may place increased emphasis on conservation development.

Alternative 3.3 Customer Planning on Other Than Critical Water Basis

KEY AREA(S):

Effects of allowing utility customers to use planning criteria other than critical water.

RESULTS:

The analysis indicated no environmentally significant changes. Critical water planning criteria are implemented under the Coordination Agreement; all customers who are parties to the Coordination Agreement would continue to be bound by its critical water planning provisions. Although the BPA contracts incorporate critical water planning criteria, they do not require customers to follow those criteria. The existing PSCs contain a disincentive against noncritical water planning, a charge that applies to Actual Computed Requirements customers (generating preference customers). The alternative would put such utilities in the same position as are IOUs under the existing contracts. Since the majority of IOUs use critical water planning criteria despite lack of a BPA-imposed disincentive, BPA concludes that the alternative would result in no significant changes. Note that alternatives for operation of the hydro system are the subject of analysis in the SOR EIS.

Alternative 3.4 Improved Ability to Exercise Provisions to Make Purchases in Lieu of Exchanges

KEY AREA(S):

Effects if BPA were able to make purchases in lieu of exchanges on shorter than the 7-year notice now required by the Residential Exchange Agreements.

RESULTS:

Shorter notice for in-lieu purchases would decrease the risk to BPA of using BPA surplus power for such purchases. The alternative would increase the risk to utilities from acquiring resources for their system load growth. The environmental effects of the shifting of risk likely are not significant.

Alternative 3.5 Shorter Contract Terms (10 years)

KEY AREA(S):

Effects of limiting BPA's Northwest Power Act PSCs to maximum 10-year terms instead of the current maximum 20-year terms.

RESULTS:

Qualitative analysis indicates that purchases from BPA by utilities would not be significantly affected. Full requirements customers probably would not change their resource planning strategies, continuing to rely on their preference rights to Federal resources. Generating preference customers already pursue resource strategies of considerable independence from BPA. DSIs could be significantly affected by the uncertainty of a shorter contract term, and could choose to terminate BPA service and look for suppliers offering longer-term certainty. In this case, DSIs could "reappear" as BPA firm load by becoming New Large Single Loads (NLSL) of utilities. If DSIs changed to retail utility suppliers, BPA could lose DSI reserves, depending on specific new contract provisions, potentially leading to a requirement for new resources or purchases of power or reserves to meet reserve requirements.

CATEGORY 4: QUALITY OF SERVICE AS A RESOURCE CHOICE

Alternative 4.1 Increase First Quartile-Type Interruptibility

KEY AREA(S):

Effects of increased DSI interruptibility as described in the DSI Options Study; also, resource planning and operational effects if an amount of non-DSI firm load equal to 50 percent or 100 percent of the DSI load were converted to nonfirm service.

RESULTS:

For Case A (50 percent of DSI load interruptible), up to 750 MW of additional load was assumed to be nonfirm by 2008 (the last study year). For Case B (100 percent of DSI load interruptible), up to approximately 2,250 MW of additional load is assumed to be nonfirm by 2008.

Conversion of firm load to less-than-firm quality of service would save or defer resource acquisition costs. A DSI rate credit for the lower quality of service would help counter the adverse impacts on DSIs of decreased quality of service, but the increased risk of restriction would significantly harm the economic viability of DSIs and decrease DSI load due to reduced production or closure of aluminum smelters or other electro-process loads. Resource operations could be adversely affected if large amounts of firm load were converted to nonfirm service ahead of need. (A large shift of surplus FELCC from spring to fall would be made for marketing purposes, to the detriment of fisheries. Shifts of smaller amounts of FELCC, such as contemplated for Non-Treaty Storage, do not have such effects.)

Conversion of firm non-DSI loads to nonfirm service may be possible under negotiated load management schemes, such as load curtailment cooperatives, although relevant information is scarce. Serving loads other than DSIs as nonfirm would be more logistically complicated, due to the number and diversity of load locations.

Alternative 4.2 No BPA Purchase Required for Certain Exercise of First Quartile Restriction Rights

KEY AREA(S):

Effects of increased DSI first quartile interruptibility if BPA was not required to purchase available replacement power at up to "reasonable cost" before restricting the first quartile to the extent it was served with shifted FELCC.

RESULTS:

The effect of this alternative would be to shift the obligation for some power purchases from BPA to the DSIs. It was not possible to quantify how frequently the increased costs might result in uneconomic costs of production for the DSIs, possibly leading to decreased production and power consumption. The alternative was found to have no effect on system operations, because the same amount of load was generally served by the same resources in both cases.

Alternative 4.3 Increase Quality of Service to First Quartile

KEY AREA(S):

Effects of increasing first quartile quality of service such that it became firm load for which BPA would be obliged to acquire resources. This alternative probably would require statutory changes but is included to provide contrast to other alternatives, which examine decreases in DSI quality of service.

RESULTS:

Conversion of nonfirm DSI load to firm quality of service would advance the costs of BPA resource acquisitions. The effect on resource operations would arise primarily from the loss of the benefits of combination service to the first quartile, that is, the dependable market for secondary energy. No change is expected in the amount of FELCC shifted, since FELCC shift tends to be used by the coordinated system to its maximum extent in any case.

Under expected loads, the increased firm load obligation from the alternative would result in increased acquisition of conservation and renewables. Addition dates for large thermal plants were advanced by small increments, and additional short-term power purchases were required. No adverse environmental effects are expected due to changes in resource operations. Loss of second quartile planning reserves is addressed in Alternative 4.4 below.

Alternative 4.4 No DSI-Type Reserves

KEY AREA(S):

Effects of loss of reserves currently provided under DSI contracts. This alternative also provides a contrast to other alternatives, which look at decreased DSI quality of service.

RESULTS:

Replacement of DSI forced outage reserves could require investment in combustion turbines or negotiation of contracts with other customers to provide such reserves from non-DSI loads. Little information is available on the feasibility of use of non-DSI loads to provide forced outage reserves, but such reserves from a multitude of smaller non-DSI loads likely would be less efficient and thus less valuable than current DSI reserves. Stability reserves could be replaced by investing in load tripping equipment, by reducing reliability of service, or by reducing the import capability of the Northwest-Southwest Intertie. Second quartile planning reserves could be replaced with short-term purchases in the event of resource delay or poor performance, or by a resource strategy to build ahead of need. Both of these options would have economic implications, but the environmental implications are not significant.

CATEGORY 5: INDUSTRIAL LOAD CONSTRAINTS ALTERNATIVES

Alternative 5.1 Larger DSI Firm Load

KEY AREA(S):

Resource planning effects of allowing total DSI Contract Demand to grow by increasing technological allowances and assuming unfettered transfer of unused Contract Demand.

RESULTS:

DSI load in 2001 could be increased by approximately 700 MW or approximately 19 percent over the Base Case projections. The additional resource development would incur the environmental impacts associated with the new resources in BPA's resource stack. (Impacts of resource alternatives are the subject of analysis in the Resource Program EIS.)

Alternative 5.2 Smaller DSI Firm Load

KEY AREA(S):

Resource planning effects of constraining DSI load size in certain ways.

RESULTS:

DSI firm contract demand for which BPA must acquire resources could be decreased by approximately 7 percent by 2001.

Alternative 5.3 Remove New Large Single Load Constraints

KEY AREA(S):

Effects of removing the rate specifications for NLSL. This alternative sets an extreme endpoint case reducing wholesale rate disincentives for large industrial development in the region.

RESULTS:

BPA resource acquisition needs would be increased by approximately 290 MW. The greatest growth was forecast to occur in the pulp and paper industry; environmental impacts could occur due to construction of new plants and to the chemicals and processes used. However, impacts would be limited because air, water, land, and other effects of industrial processes are subject to Federal, State, and local regulation.

Alternative 5.4 Increase NLSL Constraints

KEY AREA(S):

Implications of applying a new resource-based rate to any industrial load growth, even if smaller than 10 annual average megawatts (aMW). Again, the alternative sets an extreme endpoint, constraining new non-DSI industrial load growth with additional rate disincentives.

RESULTS:

BPA's resource acquisition needs would be decreased by between 73 and 116 MW by 2008. A portion of this decrease in new industrial load could be expected to result from substitution of other fuels for electricity.

DETAILED ANALYSIS OF IMPACTS

CATEGORY 1. HYDRO DEVELOPMENT AND OPERATIONS

1.1. Compliance with Fish and Wildlife Provisions as a Condition of Service

1.1.1. Method of Analysis

This alternative deals with the likelihood that a power sales contract provision would improve the implementation of the Council's Fish and Wildlife Program. The analysis is qualitative because the major effect of the alternative is to change the obligations, and possibly the roles, of various parties with respect to implementation of fish and wildlife measures. This change cannot be quantified in terms of numbers of fish or wildfowl, etc. The alternative assumes that utilities become obliged to implement the Council's Fish and Wildlife Program measures through some sort of contract provision, although other policy mechanisms of equivalent effect might be used instead.

The preferred alternative, which is the adoption of a BPA policy for enforcement of the Council's Protected Areas Rule, is the element of this alternative which addresses new hydro projects. The details of a policy will be considered in a separate process following the completion of this EIS.

The analysis consists of two steps: first, checking progress on current measures to see if there are actual implementation problems under the status quo, and second, analyzing if and how a contract provision would improve the mechanisms available to assure implementation.

An inventory was taken of Council's Fish and Wildlife Program measures that call for actions to be taken by utilities. The measures were grouped into three types: one, those that address fishery effects attributed to existing non-Federal hydro projects; two, those that address wildlife effects attributed to existing non-Federal hydro projects; and, three, those that address the development of new non-Federal hydro projects.

Then, to determine if contract provisions would improve the mechanisms to assure implementation, the following questions were asked:

(1) Does Alternative 1.1 result in clearly defined obligations of the parties?

(2) Does Alternative 1.1 duplicate existing forums?

(3) Does Alternative 1.1 add reasonable and more effective enforcement mechanisms and remedies?

This analysis assumes that implementation of a Program measure would achieve the environmental benefit intended. That is, BPA did not independently assess each measure adopted by the Council to quantify its environmental effects. Generally, the measures are intended to increase fish survival or propagation.

1.1.2. Environmental Effects

1.1.2.1. Existing Non-Federal Hydro Projects - Fishery Effects

Status of measures

The Council's Program contains over 30 measures intended to cause non-Federal utilities to conduct or participate in studies and to undertake actions to address fish concerns attributed to non-Federal hydroelectric projects. The Council explicitly relies on the hydroelectric licensing process conducted by the Federal Energy Regulatory Commission (FERC) to implement Program measures directed at non-Federal utilities. For example, Program measures provide that "FERC shall require" specific utilities to undertake specific actions.

Most of the Program measures applicable to non-Federal utilities call for research or monitoring and do not involve actions that directly increase fish survival or production. For example, Program Measure 603(c)(2) directs the fish and wildlife agencies and Portland General Electric Company (PGE) to "work cooperatively to investigate and resolve adult fish passage problems associated with PGE's Clackamas River hydroelectric dams." Other measures calling for studies are contained in Program Sections 400, 600, 700, 800, 900, and 1000.

The analysis focused on certain measures which call for explicit actions with respect to existing hydroelectric projects operated by non-Federal utilities. If FERC was enforcing the measures satisfactorily, it was concluded that the alternative would not provide a benefit.

Eight measures were identified that call for specific actions to increase fish survival. The following section indicates how FERC has considered each of these measures, and the progress to date (based on status reports from Council staff). It also examines whether power sales contract provisions would improve the implementation of the measure.

1. **403(a)(1) Mid-Columbia River Passage**. Douglas PUD to design, test, and install a collection and bypass system, approved by the Council, tailored to the unique features of Wells Dam. (Action Item 3.13)

2. **403(a)(2) Mid-Columbia River Passage**. Chelan PUD to test and install collection and bypass systems approved by the Council at Rocky Reach and Rock Island dams. (Action Item 3.12)

3. **403(a)(3) Mid-Columbia River Passage**. Grant County PUD to test collection and bypass systems at Wanapum and Priest Rapids dams and install a system at Wanapum Dam as approved by the Council. (Action Item 3.11)

Progress to date. Installation of bypass systems at the Mid-Columbia PUD projects is the subject of a FERC settlement process involving FERC and the Mid-Columbia Coordinating Committee (the Mid-Columbia PUDs, Tribes, and State and Federal fishery agencies). In several cases, the settlement process calls for specific studies and other activities to determine the effectiveness and cost of bypass measures. In other cases--for example, the Rock Island settlement--the Council amended its Program to conform to the terms of agreement among the parties.

Fishery agencies and tribes have established interim fish guidance efficiency (FGE) goals for juvenile bypass structures. For spring migration, the interim FGE goal is 70 percent of downstream migrants; for summer migration, the interim goal is 50 percent. The development of juvenile bypass facilities at other Mid-Columbia projects is evaluated based on the FGE percentage at each project.

As of August 1991, juvenile bypass modifications at all spillbays at Wells Dam were fully installed and operational, and had been approved by the fishery agencies and tribes.

For Rocky Reach, Chelan County PUD has reached a new agreement with the fishery agencies and tribes for development of bypass facilities. This agreement is effective until August 31, 1993. The FGE levels achieved in 1991 did not meet the interim goals. In 1992, Chelan will begin prototype testing of bar screens. If these tests are unsuccessful, there may not be any further options for installation of effective juvenile bypass facilities.

At Rock Island, differences in turbine intake design at the second powerhouse increase water velocity to the point that screens are ineffective or harmful to migrating fish. After lengthy study, operators have concluded that this powerhouse is unscreenable. Even without screens, mortality rates for migrating juveniles are considerably lower at this powerhouse than at other projects, due to the bulb turbine configuration. Modifications at the first powerhouse are underway to accommodate bypass screens. Prototype testing will continue in 1992.

For Wanapum and Priest Rapids, hearings are underway concerning Grant County PUD's proposal to provide screening at Wanapum only, with transportation of juveniles to below Priest Rapids instead of screening at Priest Rapids. Grant proposes studies of the transportation option over the next 4 to 5 years. A decision may be made by December 1991. Fishery agencies and tribes have not agreed to this proposal. Additional prototype testing on screens for installation is scheduled for 1993.

Would Alternative 1.1 Improve Implementation? The settlement discussions in which FERC, agencies, Tribes, and project operators are participating are of a continuing and comprehensive nature. Thus it is not likely that the alternative would hasten the implementation of bypass at the Mid-Columbia projects. A BPA contract process would be time-consuming and would duplicate or confuse an already established and productive Council-party process.

4. **403(c)(4) Tributary Passage**. Eugene Water and Electric Board (EWEB) is to construct the best available juvenile bypass facility at its Leaburg Canal Power Project. (Action Item 4.11)

Progress to date. The Council's progress report indicates that EWEB's report on Leaburg Canal fish passage progress was submitted to the Council on December 15, 1984. The report included a FY 1985 work plan developed cooperatively by EWEB and the Oregon Department of Fish and Wildlife (ODFW) to evaluate screening and bypass system modifications which were built and installed in 1984. EWEB has funded ODFW to conduct the biological evaluation of the Leaburg Project. Instream flow studies are being conducted and will lead to modification of flow regimes. This information will be used as part of the relicensing process. The project's existing license expires in 1993.

Would Alternative 1.1 Improve Implementation? Due to the continuing nature of the discussions between ODFW and the project operator, it is not likely that the alternative would hasten the implementation of installation of facilities at the Leaburg Canal project. The BPA process would merely duplicate or confuse an established and productive process.

5. **603(b)(1) Operation and Maintenance of Adult Fishways**. Grant, Chelan, and Douglas County PUDs to continue to implement fishway operating criteria for optimum fish passage for the mid-Columbia projects under their control. (Action Item 3.14.2)

Progress to date. The Council's report states that fishway criteria for the mainstem projects in the mid-Columbia are established in consultation with the fishery agencies and Tribes. The PUDs have stated in their annual reports that any changes or development of the criteria will continue to be coordinated with the fishery agencies and Tribes.

For specific projects, the Council states:

Priest Rapids/Wanapum. Grant County PUD cooperated with the fishery agencies and tribes by operating both fish ladders and spillways in accordance with established criteria. Spillway criteria for juvenile migrating salmonids supersedes spill criteria for adult passage during spring period. No changes in criteria were required in 1990.

Rocky Reach/Rock Island. The adult fishway at Rocky Reach and Rock Island dams are operated in accordance with criteria established through consultation with the fishery agencies and Tribes. Operation of the adult fish passage facilities at these projects are reviewed periodically by fishery agency representatives for compliance with agreed upon criteria. No changes in criteria were required in 1990.

Wells. No new studies have been initiated at Wells Dam to determine effects of reduced and instantaneous flows for spills on adult salmon and steelhead passage. Adult fish passage facilities are operated in accordance with criteria previously developed by the fishery agencies and Tribes in cooperation with Douglas County PUD.

Would Alternative 1.1 Improve Implementation? Based on present agreements among the parties, there do not appear to be additional benefits associated with including provisions in the PSCs. Existing efforts are achieving the full available benefit of these operating criteria.

6. **603(c)(1) Adult Passage improvements at Tributary Projects**. BPA and PGE are required by FERC to install, operate, and maintain an adult trapping facility in the Willamette Falls fishway. Funding for the facility shall be in the same proportions the original ratio of Federal-to-PGE funding of the adult fishway. (Not an Action Item.)

Progress to date. There has been little progress due to lack of Federal appropriations under the Mitchell Act which authorizes the Federal share for adult fish passage facilities at this project.

Would Alternative 1.1 Improve Implementation? Since the lack of progress is not due to FERC or the involved utility, it appears that the alternative would not improve implementation of this Measure.

7. **703(c)(2) Habitat Improvement and Passage Restoration**. PP&L (Pacific Power & Light Company) is to design and construct facilities immediately to allow upstream and downstream migration of anadromous fish at Condit Dam and to assume full responsibility for annual operation and maintenance costs of these facilities. (Action Item 4.9.1)

Progress to date. The Council's Progress report states that, on June 15, 1987, the Washington Department of Game and Department of Fisheries, the National Marine Fisheries Service (NMFS), and the U.S. Fish and Wildlife Service (USFS) published a draft report titled Estimated Anadromous Salmonid Production Potential for the White Salmon River, Washington. This document has been submitted to Pacific Power for its review. Once PP&L's review is completed, the agencies and Tribes will submit a final report to the Council.

Would Alternative 1.1 Improve Implementation? At this time, insufficient information is available to conclude whether power sales contract provisions would improve implementation of the Council's Program.

8. **903(e)(6) Additional Mitigation and Enhancement Measures**. Montana Power Company to purchase 10,000 acre-feet of water from Painted Rocks Reservoir to maintain summer and fall flows for resident fish in the Bitterroot River to mitigate impacts of the Thompson Falls project on resident fish. [Program Measure 903(e)(6), Action Item 7.24]

Progress to date. The Council's Progress Report states that Montana Power Company and the Montana Department of Fish, Wildlife and Parks (MDFWP) have reached agreement on water purchase at Painted Rocks Reservoir. The Fish and Wildlife Program was amended in 1987 to reflect this change.

Would Alternative 1.1 Improve Implementation? As this measure has been accomplished, the alternative would provide no additional benefits.

Likelihood of Improved Effectiveness

As mentioned in Methods of Analysis, the probable success of Alternative 1.1 relative to the No Action Alternative would be judged by answering three questions. First, does Alternative 1.1 result in clearly defined obligations of the parties? In the case of Council Program measures for existing hydro projects, it does not, since these measures often require extensive technical analysis and negotiation to develop the technical details of implementation and the distribution of responsibilities. Alternative 1.1 would not improve the process or change the participants.

Second, does Alternative 1.1 duplicate existing forums? It appears to do so in that parties concerned about fishery impacts have used existing FERC procedures to gain results. For example, the Mid-Columbia settlement process has resulted in specific actions to install bypass screens and construct hatcheries. In fact, when the FERC settlement process for the Rock Island project produced fish measures that differed from the Council's Program, the Council amended its Program to reflect the FERC settlement process. There is no basis to conclude that Alternative 1.1 would improve a process that is already characterized by numerous opportunities to achieve settlements and a willingness by the various parties to incorporate agreed-upon solutions.

It appears that Alternative 1.1 might result in more effective implementation of Program measures than relying on FERC alone, particularly when a utility is not undergoing a licensing or relicensing procedure. FERC may reopen a project license without the agreement of a hydro project licensee, but the process is difficult and unlikely. Under potential alternative contract provisions, BPA would have to retain its authority to apply independent judgment to a fact situation involving implementation of Program measures. However, the above status check yielded no evidence that current implementation is significantly impeded. In the Intertie Access Policy process, BPA found no evidence that existing projects are operated in a manner contrary to the Council's Program or adversely affecting BPA fish investments. In 1988, BPA stated:

> We do not believe there is sufficient evidence to indicate that existing projects are presently operating contrary to the Council's Program or that the Council has been unable or unwilling to implement Program measures applicable to existing projects. [Administrator's Decision, Long-Term Intertie Access Policy (May 17, 1988), p. 160.]

The present implementation of the Fish and Wildlife Program is acceptable to the Council. Council progress reports indicate that Program measures applicable to utility-owned facilities are being implemented reasonably. The Council has not formally identified any Program measures it believes have not been applied suitably by FERC.

Third, does Alternative 1.1 add reasonable and more effective enforcement mechanisms and remedies? The design of fair and practicable enforcement measures would be difficult, though not impossible. The lack of clarity of obligations of the parties described above would forestall the application of such measures until the customer's obligation was defined. The contract provisions themselves might be subject to challenge if a party's obligations were ambiguous. Such challenges might lead to less effective enforcement.

1.1.2.2. Existing Hydro Projects - Wildlife Effects

The Council has not adopted measures that assign specific wildlife mitigation responsibilities for non-Federal hydro project operators.

In order to avoid a duplication of effort, the Council has determined that it will not set forth specific measures for non-Federal projects. Instead, the Council ". . . will monitor the FERC licensing and relicensing proceedings and comment and intervene where appropriate."

Given the Council's decision, the alternative would not address wildlife mitigation requirements for existing projects in the PSCs. The Council addresses the effects of proposed developments on wildlife in its Protected Areas program. (See the next section on new hydro facilities.)

1.1.2.3. New Hydro Projects - Protected Areas Rule

Protected Areas, as adopted by the Council, are specific stream reaches in the Pacific Northwest withdrawn from hydro development due to the presence of high-value wildlife and anadromous and high-value resident fish. Stream reaches also are protected where future investments in habitat, hatchery, passage, or other projects may result in the presence of anadromous fish. The purpose is to protect these stream reaches from development of new hydroelectric projects.

The Council's data on Protected Areas indicates that 108 hydro projects are proposed for development within Protected Areas. Of those 108, sixty-seven proposed projects are within the Columbia River Basin. Under the Council's rules, 28 of these 108 projects (17 within the Basin) would likely be exempted from the Protected Areas prohibition on development because they are proposed additions or alterations to existing structures or impoundments.

BPA's Long-Term Intertie Access Policy (LTIAP) supports the Protected Areas rule by reducing a utility's access to the Pacific Northwest-Pacific Southwest Intertie if the utility builds or acquires a project located in a Protected Area within the Columbia River basin. This provision in the Intertie Access Policy is expected to discourage some development of resources in Protected Areas. However, the Intertie Access Policy provision will not necessarily discourage Protected Area hydro resource development if it involves a utility which does not use the Intertie.

In establishing the Intertie Access Policy, BPA determined that its primary interest was to protect BPA's fish and wildlife investments in the Columbia River Basin. Although recent statutory changes may have provided FERC with increased fish and wildlife responsibilities, those provisions do not require FERC to protect BPA fish and wildlife investments. FERC staff comments to the Council indicate that Protected Areas would be taken into account on a case-by-case basis in licensing proceedings. FERC has not officially indicated how it will take Protected Areas into account in its processes.

Application of the three questions indicates that power sales contract provisions enforcing Protected Areas may be more effective than the status quo in preventing adverse environmental effects of new hydro facilities.

First, does Alternative 1.1 result in clearly defined obligations of the parties? A Protected Areas provision would provide a clear rule for a utility to follow to avoid violating its power sales contract by acquiring a project in a Protected Area. Accidental or mistaken noncompliance is unlikely.

Second, does Alternative 1.1 duplicate existing forums? BPA has already determined that Protected Areas provisions would not duplicate existing forums in that FERC's standards for decisionmaking did not include protection of BPA's investment. In connection with the Intertie Access Policy, BPA found that Protected Areas provide ". . . the best assurance for fish and wildlife protection with the least amount of procedural duplication." [Administrator's Decision, Long-Term Intertie Access Policy (May 17, 1988), p. 145.]

Third, does Alternative 1.1 add reasonable and more effective enforcement mechanisms and remedies? The answer to this question must be very general at this point because the actual mechanisms and remedies must be determined through a contract negotiation process. Several general types of enforcement measures could be pursued to assure implementation of a Protected Areas provision. For example, resources developed in Protected Areas could be excluded from addition to the Firm Resource Exhibit. Also, the costs of such resources could be excluded from the Average System Cost of the utility in calculations for the Residential Exchange, although this likely would require a change in methodology. Such changes can be made only after a consultation process and FERC approval.

Other implementation provisions could include surcharges, a "Protected Areas rate," reductions to or limitations on sales, or other provisions which are disincentives in other transactions applied elsewhere; e.g., wheeling agreements. The development of a BPA policy for Protected Areas enforcement could result in disincentives for new hydro development without necessarily requiring negotiation of a contract amendment. The Stage Two process for the preferred alternative will address the various enforcement mechanisms which could be incorporated into a BPA Protected Areas policy.

The analysis indicates that Alternative 1.1 could provide environmental benefits based on the Protected Areas rule for stream reaches within the Columbia River Basin and outside of it, if BPA were to decide to extend its policy to those areas.

1.2. No Shift of Firm Energy Load Carrying Capability for DSI First Quartile

1.2.1. Method of Analysis

For alternatives such as this one, which raise operational issues relevant to fisheries, the analysis used two models. The System Analysis Model (SAM) was used to assess operational changes such as changes in flow, spill, and reservoir elevations. The FISHPASS model was used to assess fish survival. (Information on models used is provided in Appendix G.) DSI effects were assessed qualitatively.

System Analysis Model Assumptions. The SAM analysis assumes for the Base Case that BPA is obligated to serve the DSI first quartile as specified in the 1981 DSI PSCs; that is, with a combination of surplus power, nonfirm energy, and borrowing techniques (see Appendix C for a detailed description of borrowing techniques).

Availability of surplus firm power to serve the first quartile is determined by load and resource projections and assumed levels of surplus firm power sales. For the term of the analysis, the DSIs are assumed to retain their existing rights to buy replacement energy through BPA under terms of the Industrial Replacement Energy (IRE) Agreements. The Base Case also assumes that BPA and other Coordination Agreement parties continue to shift and shape FELCC to the full extent of their rights. (See Appendix C.)

When the hydro system starts out full, BPA may use FELCC shift (shift of energy from later to earlier years of a critical period), advance energy (draft of a reservoir below ordinarily allowed levels), and flexibility energy (energy shifted among months of an Operating Year) to serve the DSI first quartile load. In years in which the hydro system does not refill, these types of energy may not be available for this purpose. (See Appendix C for detailed explanations of these terms.) In SAM, the amount of FELCC shift to meet first quartile load is limited to 1,000,000 Megawatthour (MWh); of advance energy, 800,000 MWh; and of flexibility energy, 750,000 MWh. Together these amounts are sufficient to serve the entire first quartile load September through December.

Under this alternative, FELCC shift, advance energy, and flexibility energy are assumed not to be used at any time for service to the first quartile. Instead, the DSI first quartile will be served only with nonfirm energy, surplus firm energy, or purchases from outside the Pacific Northwest system when available (SAM assumes these purchases are made from Canada). SAM assumes continued use of FELCC shift by the coordinated system to meet firm load and to displace combustion turbines. Flexibility energy may still be used to meet firm load, but advance energy may not. In addition, without the use of borrowing techniques, BPA will have no third quartile restriction rights.

The Least Cost Mix Model results for the No Action Alternative are used for the load/resource balance for this Alternative, since no changes occur to load/resource balance. The Least Cost Mix Model produces a list of resources arranged in order of cost (see Appendix G).

1.2.2. Environmental Effects

The environmental implications of this alternative are linked to changes in the seasonal shaping of firm energy. If firm energy generation is heavier in one season than another, the resulting hydro operation effects on fish and wildlife are different. Under the No Action Alternative, some FELCC is shaped into the months of September through December for service to the DSI first quartile. Under Alternative 1.2, this seasonal shaping would not take place; the only shaping that would take place is the shifting allowed the parties of the Coordination Agreement.

1.2.2.1. Future Resource Development

Alternative 1.2 has no direct effect on future resource development. Use of energy "borrowing" techniques for any purpose does not affect the firm load/resource balance, and thus does not change the need to develop new firm power resources. Further, BPA does not plan resources to serve the DSI first quartile.

Alternative 1.2 could affect the need for future resources indirectly. As explained below under DSI Effects, the increased exposure to restrictions or increased power purchase costs could adversely affect the economic viability of some DSIs, i.e., cause shutdowns. Therefore, if some DSIs ceased operating, total DSI firm loads upon which firm resources are planned could be less under Alternative 1.2, leading to a reduced need to develop new resources, net of the need to replace lost DSI reserves from shutdowns.

Appendix F discusses the impacts of the operation and development of new resources.

1.2.2.2. Resource Operations

1.2.2.2.1. Changes by Type of Resource

Appendix H-5 shows the projected changes in annual average generation by type of resource for all the alternatives for the base scenario and all sensitivities analyzed. Alternative 1.2 shows very small, irregular changes in generation relative to no action; nuclear generation is consistently unchanged. The same is generally true for all six of the sensitivity cases addressing different assumptions regarding Northwest and Southwest loads and gas prices analyzed. Annual average generation by resource type is not significantly affected by disallowing the use of borrowing techniques to serve the DSI first quartile. The monthly distribution of generation by resource type, however, does change. By not using borrowing techniques for first quartile service, hydro generation tends to decrease in the fall and increase the rest of the year. See the discussion of reservoir elevation impacts in Section 1.2.2.2.2 below.

Two of the three types of borrowing techniques, Flexibility and Advance Energy, are methods of moving energy within the same operating year. Thus, they redistribute the hydro generation during the year without necessarily affecting the annual generation. The third type of borrowing technique, shifted FELCC, does change the amount of annual energy available. However, FELCC can be shifted for uses other than service to the first quartile (e.g., to displace combustion turbines or to prevent a firm energy deficit), so shifted FELCC is still used in Alternative 1.2. Shift energy is distributed differently throughout the year depending on the reason for the shift. There generally is little difference between Alternative 1.2 and the No Action Alternative in the amount of shift on an annual basis.

1.2.2.2.2. Hydro System Impacts

Anadromous and Resident Fish. Changes in hydrosystem operations can affect anadromous and resident fish in a number of ways. (A complete description of the criteria used for evaluating the impacts of hydro operations on anadromous fish may be found in Appendix H-1a.) A decrease in flow during the spring migration period can increase the travel time for smolts trying to reach the ocean and increase their exposure to predators and disease. High flows at Vernita Bar in the Hanford Reach during the fall chinook spawning period (October 15 through November) could make greater than normal spring flows necessary to protect the emerging fry. If monthly average flows exceed 125 kcfs at Vernita Bar during the fall, it is possible that additional fish may go unprotected through emergence, as the maximum instantaneous protection level is capped at 70 kcfs.

Flow data for the analysis were evaluated by water condition. Low water years, those in which the January through July volume runoff at The Dalles was less than 70 MAF, represent the lowest 10 percent of the water years. Average water conditions, years in which the runoff was between 70 and 125 MAF, make up 80 percent of the water years. High water years are those in which the volume runoff exceeds 125 MAF at The Dalles, and make up the remaining 10 percent.

Serving the DSI first quartile load without the use of shift, flexibility, or advance energy decreased fall flows on the Columbia River between 1 and 2 kcfs in the fall and increased flows 0 to 2 kcfs in the winter and early spring. This was true in each of the three water conditions analyzed. There was no change to Snake River flows. Water Budget flows on the Columbia River were maintained.

Flows at Vernita Bar, downstream of Priest Rapids Dam, were 0.70 percent less likely to exceed 125 kcfs during the fall spawning period, and 0.90 percent more likely to remain above 70 kcfs during the hatching and emergence phases.

Changes in overgeneration spill also affect anadromous fish migration. Spill is used to pass fish over the spillways rather than through generating turbines. There was very little change to the amount of overgeneration spill available in this alternative. Overgeneration spill increased by only 0.30 percent for the period April through August.

Both flow and spill affect the overall survival of smolts as they pass through the hydroelectric system. FISHPASS models the passage of smolts through the system and calculates the relative survival rates for each species. This alternative showed very little change in the overall system survival. Relative system survival increased between 0 and 0.2 percent in some years for sockeye and subyearling fish. There was no increase or decrease in the relative system survival of steelhead or yearling fish. Survival changes for individual stocks entering the various pools ranged from -0.3 to +0.8 percent. This alternative would have very little effect on anadromous fish.

Comparison of data between Alternative 1.2 and the Base Case for overgeneration spill; relative system survival and frequency of relative survival changes exceeding 1 and 5 percent; monthly average flow at Lower Granite, Priest Rapids, and The Dalles; and frequency analysis of meeting the Vernita Bar requirements and Columbia River Water Budget; can be found in Appendices H-1d through H-1h.

Resident fish, which live in reservoirs or freshwater streams but do not migrate to the ocean, are primarily affected by flow and fluctuations in reservoir elevation. (A complete description of the criteria used for evaluating the impacts to resident fish may be found in Appendix H-1a.) The period of greatest biological activity for fish residing in the reservoirs is between April and November; September through November is the predominant period of fish growth. Excessive fluctuation in reservoir levels during this time can affect these fish. Reservoir elevations were evaluated using low, average, and high water conditions as described above.

Reservoir elevations increased in all water conditions under Alternative 1.2. The greatest increases occurred in the spring of low water years. Hungry Horse showed the greatest gain in elevation, averaging 4.1 feet during the April through November period in low flow years. Dworshak gained 2.2 feet and Libby gained 1.6 feet during this period. Increases in elevation generally were within one foot of no-action levels for both average and high water conditions. Elevation changes at Grand Coulee were within one foot in all water conditions. The frequency of the reservoir level decreasing more than 5 feet from the Base Case was small, generally less than 3 percent at all reservoirs. The frequency of reservoir levels being greater than 5 feet from the Base Case ranged from 2 to 15 percent at Dworshak, 0 to 3.5 percent at Grand Coulee, 3.5 to 19 percent at Hungry Horse, and 0 to 7.7 percent at Libby. These increases in reservoir elevations may provide some small benefit to resident fish, particularly in low flow years. Comparison of data between Alternative 1.2 and the Base Case for end-of-period reservoir elevations and the frequency of change in reservoir elevation greater than 5 feet for Dworshak, Grand Coulee, Libby, and Hungry Horse can be found in Appendices H-1j and h-1k.

Fish residing in the Kootenai and Flathead rivers depend on flow. Flows on the Kootenai River downstream of Libby Dam should remain above 4.0 kcfs except in years of extremely low runoff, when flows can be as low as 3.0 kcfs. Flows at Columbia Falls, on the Flathead River below Hungry Horse Dam, should remain between 3.5 and 4.5 kcfs mid-October through mid-December and remain above 3.5 kcfs the remainder of the year.

Changes to the mean monthly flows at Libby and Columbia Falls were small, generally less than 1 kcfs. There was very little change in the frequency of flows less than 4.0 kcfs at Libby or greater than 4.5 kcfs October through December at Columbia Falls. This alternative would have no effect on resident fish residing in these streams. Comparison of data between Alternative 1.2 and the base case for monthly average flow at Libby and Columbia Falls and frequency of flows being less than 4.0 kcfs at Libby, and greater than 4.5 kcfs and less than 3.5 kcfs at Columbia Falls can be found in Appendix H-1i.

The results of this analysis did not change under different assumptions with respect to growth of Northwest loads, growth of Southwest loads, and gas prices.

A complete description of the criteria used for evaluating the impacts of hydro operations on anadromous fish may be found in Appendix H-1a. Comparison of data between the Alternative and the Base Case for overgeneration spill; relative system survival and frequency of relative survival changes exceeding 1 and 5 percent; monthly average flow at Lower Granite, Priest Rapids, and The Dalles; and frequency analysis of meeting the Vernita Bar requirements and Columbia River water budget; can be found in Appendices H-1d through H-1h.

A complete description of the criteria used for evaluating the impacts of hydro operations on resident fish may be found in Appendix H-1a. Comparison of data between the Alternative and the Base Case for monthly average flow at Libby and Columbia Falls and frequency of flows being less than 4.0 kcfs at Libby, and greater than 4.5 kcfs and less than 3.5 kcfs at Columbia Falls; and end-of-period reservoir elevations and the frequency of change in reservoir elevation greater than 5 feet for Dworshak, Grand Coulee, Libby, and Hungry Horse and can be found in Appendices H-1i through H-1k.

The results of this analysis did not change under different assumptions with respect to growth of Northwest loads, growth of Southwest loads, and gas prices.

Recreation. Recreation analysis was performed for Grand Coulee (Lake Roosevelt), Dworshak, Libby, and Hungry Horse through the computation of recreation indices. The derivations of these indices are described in Appendix H-2. Larger values for the recreation indices show improved opportunities for recreation at the reservoirs. Appendix H-2 also shows the recreation indices computed for the four reservoirs for all alternatives and their differences from the Base Case for the expected gas price and Northwest and Southwest load growth assumptions. Alternative 1.2 resulted in small changes in the recreation indices for the four reservoirs. For example, the seasonal average recreation index increased by less than 1 percent for Dworshak, Lake Roosevelt, and Libby, and increased by less than 3 percent for Hungry Horse under Alternative 1.2 relative to the No Action Alternative. Detail on changes at specific reservoirs is included in the section on Anadromous and Resident Fish, above.

Recreation impacts for Lake Pend Orielle are analyzed in terms of the probability of the elevation of that reservoir being at least 2,054 feet at the end of April, a level that enhances the annual Kokanee and Kamloops Fishing Derby, which occurs around May 1 each year. This probability is tabulated for selected years for all the alternatives in Appendix H-3. The probability is essentially unchanged for Alternative 1.2 relative to the No Action Alternative.

System Refill. Alternative 1.2 resulted in very small and nonuniform differences from the No Action Alternative in the projected probability of July refill of the hydrosystem (See Appendix H-4). Changes result from a different operation of the hydro system throughout the year, but the similarity in annual average generation keeps the changes in refill small.

Irrigation. Levels of allowable irrigation withdrawals are determined by the individual states and are established water rights. Hydro operation planning is developed around flows that reflect irrigation withdrawals. In most areas of the Columbia River Basin, river operations affect irrigation only to the extent that coordination is sometimes necessary to allow irrigators to move their pump intakes in response to changes in reservoir or river levels. These types of impacts would not be changed by altering the PSCs.

However, pumps for the Columbia Basin Project are located at Grand Coulee. As the level of Lake Roosevelt drops, pumping becomes more difficult; at some levels, pumps will not operate or may be damaged if run. There is currently a requirement for Lake Roosevelt to be at or above 1,240 feet at the end of May for irrigation. If that constraint is not met, there would be some potential for drawdown of Banks Lake, which could have an adverse effect on the fishery and recreation there. Alternative 1.2 did not change the likelihood of Lake Roosevelt's elevation being at or above 1,240 feet relative to the No Action Alternative.

1.2.2.2.3. Thermal Plant Operations

Coal and Combustion Turbine Plant Generation Changes. Changes in the degree of operation of coal plants dedicated at least partially to supplying power to the region are shown in Appendix H-6. Changes are shown on an annual basis in units of average annual megawatts. The SAM also shows small, irregular changes in coal-fired generation at individual plants for Alternative 1.2 relative to the No Action Alternative with the expected loads and gas price. The same is generally true of the analyses done with the other (sensitivity) assumptions regarding gas price and Northwest and Southwest load growth. In some of the sensitivity cases, there are some relatively large (~10 percent) changes between the No Action Alternative and Alternative 1.2 for some plants in some years, but there are no clear trends. This is consistent with the findings for resource operations in general and for hydro resources described previously. As hydro generation is redistributed throughout the year, coal generation may change to meet the same load shape.

Projected operation of existing combustion turbines serving the region and included as resources in SAM is also shown in Appendix H-5. Alternative 1.2 has little effect relative to the No Action Alternative on the operation of existing combustion turbines, including the Beaver facility. In the Northwest Low Load Case, there is no change at all in combustion turbine operation between Alternative 1.2 and the No Action Alternative.

Air Quality. Air quality impacts result from changes in operation of coal plants and combustion turbines. Less annual generation at these types of facilities means that annual average concentrations of air pollutants in the areas affected by the plants would be lower. There would not necessarily be a reduction in the peak concentrations of air pollutants resulting from the plants.

Using the methodology described in Appendix H-7, air quality impacts were determined for the individual coal plants affected. The air quality impacts for each plant for all the alternatives and for expected gas prices and loads and high Northwest loads are also tabulated in Appendix H-7. The analysis found that air quality impacts of Alternative 1.2 resulting from changes in coal-fired plant operation were negligible in all cases.

The differences were small between Alternative 1.2 and the No Action Alternative in generation projected by SAM for individual existing combustion turbine generation facilities. The ambient levels of air pollutants attributable to these types of facilities seem typically very low (see Appendix H-7). Therefore, the air quality impacts of Alternative 1.2 relative to No Action are negligible.

Fuel Use. More or less generation by coal-fired plants means more or less consumption of coal, a nonrenewable resource. Using the methodology described in Appendix H-8, changes in coal consumption were determined for coal-fired plants supplying power to the region. The coal consumption impacts for each plant for all the alternatives and for expected gas prices and loads and high Northwest loads are tabulated in Appendix H-8. The analysis showed coal consumption impacts of Alternative 1.2 to be negligible in all cases.

Differences in generation by gas turbine generating facilities, including the Beaver facility, between the No Action Alternative and Alternative 1.2 were also very small. Thus it can be concluded that the impacts on gas and oil consumption of Alternative 1.2 are small. For example, the largest increase between the No Action Alternative and Alternative 1.2 in generation at the Beaver facility for any year of the SAM analysis with expected loads and gas prices was 2.9 aMW in 1991. Assuming combined cycle operation of the plant, this equates to an increase in Northwest consumption of natural gas of about 0.8 percent. Over the 20 years of study, under Alternative 1.2 Beaver is projected to require about 396 MCF, or about 1.4 percent, more natural gas than under the No Action Alternative when expected loads and gas prices are assumed. When high Northwest loads are assumed, Beaver is projected to use about 10,200 million more cubic feet of natural gas than under the No Action Alternative over the 20 years of the study, an increase of about 10.1 percent.

Land Use. Changes in coal plant generation cause changes in land use from more or less mining of coal during a time period. The coal-fired generating plants supplying power to the region, except Valmy, rely on surface coal mines for their fuel supply. Thus, generation changes mean that more or less surface area is disturbed as a consequence of mining each year. It is likely that the total surface area disturbed for coal mining will be unchanged under this alternative, however, because the amount of economically recoverable coal at a mining property is unchanged. Mining is likely to occur until all economically recoverable coal is mined.

Using the methodology described in Appendix H-8, changes in annual disturbance of land for coal mining were determined for the individual surface coal mines affected. The land disturbance impacts for each plant for all the alternatives for expected gas prices and loads and for high Northwest loads are tabulated in Appendix H-8. The analysis found that land disturbance impacts of Alternative 1.2 resulting from changes in coal-fired plant operation were negligible in all cases.

Water Use. The Boardman, Centralia, Bridger, and Colstrip coal-fired generating plants secure water from the respective rivers indicated in Table 1.2.1. The Valmy coal-fired plant secures ground water for plant use from the Valmy aquifer via wells. Changes in the operation of these plants can be expected to result in changes in their water consumption and, therefore, the amount of water which remains for other uses. Impacts on the supply of surface and ground water from changes in operation of the coal-fired generating plants were conservatively computed with the method used for the Final Intertie Development and Use Environmental Impact Statement and described in Appendix H-8. Tables 1.2.1 and 1.2.2 show the results. It should be noted that the water consumption analysis was based on the positive and negative differences in generation between Alternative 1.2 and No Action of the largest magnitude throughout the 20 years of the SAM analysis. Therefore, the results shown in Tables 1.2.1 and 1.2.2 are only for 2 particular years, which are not necessarily uniform for the various plants. Differences in water use for all other years of the SAM analysis are of smaller magnitude than those shown on the Tables. Water use impacts for the Boardman and Colstrip plants tend generally to be very small simply because they draw their water from relatively large rivers, the Columbia and the Yellowstone. Also, the minimum discharge upon which the percentages in the second to the last column of Table 1.2.1 are based is an artificial value for annual minimum stream flow computed by multiplying the minimum discharge given in the seventh column of the Table by the number of days in a year (i.e., 365). This makes the analysis very conservative.

The impacts on both ground and surface waters of Alternative 1.2 relative to the No Action Alternative are very small regardless of whether expected loads and gas prices are assumed, or whether high Northwest loads are assumed. The largest changes in water use by any plant relative to a very conservatively estimated minimum annual flow in the stream acting as the source of water (or, for the Valmy plant, aquifer recharge) were less than 1 percent. (Water use impacts were not calculated for the Corette plant since the differences in generation between Alternative 1.2 and the No Action Alternative were very small.)

Table 1.2.1

ALTERNATIVE 1.2: MAXIMUM IMPACT ON SURFACE WATERS OF THE PACIFIC NORTHWEST

STATE	PLANT	WATER BODY	MEAN ANNUAL DISCHARGE (AC-FT)	YEARS OF RECORD	RECENT YEAR DISCHARGE (AC-FT)	MINIMUM DISCHARGE (AC-FT/DAY)	YEAR	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN GENERATION (aMW)	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN WATER USE (AC-FT)	PERCENTS OF MINIMUM DISCHARGE 1/	RECORD RATING
EXPECTED LOADS AND GAS PRICE											
OR	Boardman	Columbia River	140100000	104 yrs	165700000	24000	1968	5.3	129	0.0015	Excellent
								-0.1	-2.44	-0.00003	
WA	Centralia	Skookumchuck River	183300	1930-82	238600	167	1982	5.4	117	0.19	Good
								-6.1	-132	-0.22	
WY	Bridger	Green River	1277000	33 yrs	1677000	337	1955	0.8	17.3	0.01	Good-Poor
								-8.4	-181	-0.15	
MT	Colstrip	Yellowstone River	8620000	1978-84	8780000	12246	1984	0.6	13.0	0.0003	—
								-4.5	-97.2	-0.0022	
HIGH NORTHWEST LOADS											
OR	Boardman	Columbia River	140100000	104 yrs	165700000	24000	1968	4.7	115	0.0013	Excellent
								-1.9	-46.4	-0.0005	
WA	Centralia	Skookumchuck River	183300	1930-82	238600	167	1982	17.0	367	0.60	Good
								-8.2	-177	-0.29	
WY	Bridger	Green River	1277000	33 yrs	1677000	337	1955	0.0	0.0	0.0	Good-Poor
								-9.0	-194	-0.16	
MT	Colstrip	Yellowstone River	8620000	1978-84	8780000	12246	1984	0.2	4.32	0.0001	—
								-2.6	-56.2	-0.0013	

1/ Percent of Minimum Discharge computed assuming minimum discharge occurs over the course of an entire year. This method tends to overstate the actual expected impacts.

Table 1.2.2

ALTERNATIVE 1.2: MAXIMUM IMPACT ON GROUNDWATER IN THE PACIFIC NORTHWEST

STATE	PLANT	WELL LOCATION	AQUIFER RECHARGE OR YIELD (AC-FT/YR)	LARGEST POSITIVE AND NEGATIVE CHANGES IN GENERATION (aMW)	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN WATER USE (AC-FT)	PERCENT OF RECHARGE OR YIELD
EXPECTED LOADS AND GAS PRICE						
NV	Valmy	Valmy aquifer near Valmy	9000	1.8	25.8	0.29
				-2.1	-30.1	-0.33
HIGH NORTHWEST LOADS						
NV	Valmy	Valmy aquifer near Valmy	9000	3.5	50.2	0.56
				-1.1	-15.8	-0.18

1.2.2.3. DSI Effects

The alternative could have significant effects on DSI economic viability. Restrictions of the first quartile DSI load frequently would be between 50 aMW and 200 aMW under all assumptions of Northwest and Southwest load and gas price except low Northwest loads. First quartile restrictions in this range may adversely affect the economic viability of some aluminum plants and lead to increased unemployment. Because it is not possible to quantify the severity of this effect, however, it is not reflected in the SAM analysis results, i.e., no attempt was made in the SAM analysis to adjust the size of the DSI load to account for this effect. Effects of frequent first quartile restrictions include the impacts of shutdowns, and the potential effects, such as changes in resource and transmission planning, of DSIs obtaining service from other suppliers instead of BPA. (These effects and other secondary impacts of DSI restrictions or shutdowns were evaluated in the DSI Options EIS, April 1986.)

1.3. Limit Changes Within Operating Year

1.3.1. Method of Analysis

This alternative is analyzed qualitatively because quantitative analysis would have required speculative sets of assumptions on the customer load changes studied here. The different sizes, timing and combinations of possible customer load changes are so numerous that model analysis would be less useful than a qualitative explanation of the decisions and operations involved in response to changing electric loads. The discussion explains the potential operational effects of load changes within the Operating Year by any BPA power sales contract customer compared to the existing contractual provisions in the No Action alternative as explained in Chapter 2.

1.3.2. Environmental Effects

Under the No Action Alternative, BPA could cover firm load increases by utilizing one or more of the following options:

1. BPA could use Flexibility Energy under the Coordination Agreement to move energy from future months of the Operating Year. The extent of the use of Flexibility Energy is limited by the Coordination Agreement (see Appendix C) and cannot exceed hydro operational limits in the operating plan for that period.
2. BPA could serve the firm load increases with its surplus firm energy, if available, limited by the operating plan for the year.
3. BPA could use nonfirm energy, to the extent available, instead of marketing it to nonrequirements load.
4. BPA could recall energy pursuant to contracts that allow or require recall; and
5. BPA could purchase energy from other entities.

If the PSCs eliminated the customer rights to make firm load increases, BPA's DSI customers and all utility customers would effectively be served as are utilities which are currently Planned or Contracted Requirements Customers (see Appendix B description and Figure B-1). That is, during the contract year, the customers would receive firm energy from BPA equal to the amount shown in firm planning for that year and no more. Such an arrangement would provide increased planning certainty for BPA.

Prior to the recent load/resource balance, BPA and other Northwest utilities had surplus firm energy to sell. Under Alternative 1.3, it is likely that the utilities and DSIs would have purchased this surplus firm energy to cover their remaining firm load and serve potential overruns. Since the surplus firm energy would have been marketed both with and without this alternative, reservoir operations for BPA and the other Northwest utilities would remain the same as under the No Action Alternative. Therefore, no effect on fish or wildlife would be expected.

Since load/resource balance, the utilities and DSIs do not have additional Northwest surplus firm energy to cover their firm load overruns. They must therefore either enter into energy acquisitions (purchases or exchanges) from utilities with surpluses in the Southwest or other regions or build their own resources to cover the overruns. Either option would have a significant economic impact on the customer and possible fish and wildlife impacts. In addition, if DSI and utility customers were obligated to provide generating resources to cover the risk of short-term firm load changes, there would tend to be proliferation of surplus resource capability, favoring low-capital-cost resources with short lead times. Resource development would diverge from the types of resources that BPA would acquire in accordance with the priorities and cost-effectiveness criteria of the Northwest Power Act to the extent that DSI and utility resource priorities differed from BPA's. Again, BPA and the Northwest utilities will operate to produce their FELCC both with and without this alternative, so no change in reservoir operation would result.

During periods of load/resource balance when BPA needs to purchase energy, competing with the utilities and DSIs for available energy, at least over the short run, could drive the price of energy up, further increasing the region's cost.

CATEGORY 2. CONSERVATION

2.1. Conservation Compliance as a Condition of Service

2.1.1. Method of Analysis

Qualitative analysis examines the potential impact on BPA and the region of a provision in the PSCs requiring customers to implement conservation programs offered by BPA or similar programs of their own design. The analysis takes into account BPA's program experience, recent progress in favor of least-cost planning, and utility regulatory commission interest in removing barriers to conservation by IOUs. Qualitative analytical methods are used for this alternative because the major issue is whether a contract obligation is more likely to influence BPA customers to implement or support conservation than the noncontractual factors that currently influence customer conservation. Quantitative methods would not be useful to measure the relative strength of the influence.

2.1.2. Contract Provision Analysis

How are generating resources accounted for in the contracts? Under section 12 of the Utility PSCs, customers maintain Firm Resource Exhibits (FREs) showing the resources they will use to serve their firm loads. Generating resources and contracts for the delivery of power are listed in these FREs, along with peak and annual average energy capabilities.

For Metered Requirements customers, the actual outputs of the FRE resources are used to determine the amount of firm requirements power the customer has a right to receive from BPA. For Computed Requirements customers, which includes Actual and Planned Computed Requirements customers (currently all generating preference customers) and Contracted Requirements customers (currently all IOUs), there is an additional step. The Computed Requirements customer uses its FRE list of resources and develops an Assured Capability Exhibit each year showing the amounts of peak and energy that the customer will produce from its own resources during each month of the operating year. Once the Assured Capability Exhibit is completed, the customer is normally obliged to produce that planned peak and energy. Computed Requirements customers have the right to purchase from BPA only the amount by which their loads exceed this Assured Capability.

DSI contracts have no provisions on accounting for customer resources. DSI PSC sections 4(a) and 4(d) provide that BPA is to sell power for existing DSI facilities (except for certain wheel turning loads served by local utilities) up to their Contract Demands, making additional resource development or purchases by the DSIs generally unnecessary, unless DSIs desire to expand so that power needs exceed amounts available from BPA. Section 4(d) allows DSIs to buy power from other utilities or to secure power from other sources for new facilities. The DSI PSC does not impede a DSI from implementing conservation, however, since it can reflect a reduced loss achieved through conservation by reducing Contract Demand or could use the power conserved elsewhere in their facility. Aluminum DSIs have obtained funding from BPA for energy efficiency improvements under BPA's Con/Mod Program, which requires that the participating DSI's Contract Demand be reduced to reflect the reduced need for power once efficiency improvements have been completed.

The Residential Exchange Agreements identify generating resources allocated to the exchange load through the average system cost fillings, which are outside the scope of this EIS.

How is conservation accounted for in the contracts? In the Utility PSCs, conservation resources are not listed in the FREs for purposes of determining how much electric power the customer must supply on its own. Instead, conservation is used in the development of Estimated Firm Loads. The process for doing this depends on the size and technical sophistication of the utility. Small utilities with less technical capability develop their forcasted loads with assistance from BPA. Large utilities develop load forecasts in regional planning processes, such as the Coordination Agreement and the PNUCC Northwest Regional forecast (NRF). BPA uses the aggregated estimated loads of its DSI and nongenerating utility customers and the load estimates produced by its larger generating customers in its own load forecasts for the Coordination Agreement and long-term planning.

Conservation is, however, accounted for with generating resources for other determinations under the Utility PSCs.

Under Section 7, Allocations in Event of Insufficiency, conservation is added to other resources for purposes of determining if the customer has done its part to develop resources sufficient to serve its own load growth. Section 7 allocation procedures have not received much attention during the recent surplus, but are important in the event of resource deficits.

In Section 11, Compensation in Event of Regional Curtailment, conservation may be either included with generating resources, or used as a deduction from Actual Firm Load. Section 11 is designed to alleviate cash flow problems for Metered Requirements and Actual Computed Requirements customers who lose billable load in times of regional curtailment. BPA will pay the customer the amount per kWh by which the customer's average revenue from retail sales of electric energy exceeds the wholesale firm power rate the customer would have paid to BPA. The purpose of accounting for conservation here is similar to the purpose of such accounting in Section 7, i.e., customers who have not developed sufficient resources to serve their own load growth will receive reduced benefits.

The DSI PSCs and Residential Exchange Agreements do not provide a special method of accounting for conservation. BPA's DSI customers would merely reflect any conservation they have undertaken in specifying their Operating Demand. Hence, the equitable accounting question doesn't arise in the same way as for BPA's utility customers. Under the Con/Mod agreements, which are outside the scope of this EIS, BPA treats DSI conservation undertaken under Con/Mod as a resource which can be used in the future for the region. BPA can reduce DSI Contract Demand to capture the conservation.

The Residential Exchange Agreements require extensive documentation of exchange loads, resources, and resource costs for the average system cost filings. Conservation can be used to adjust exchange loads, and certain conservation costs can be included with other resource costs. This information is included in the average system cost filings, which are outside the scope of this EIS.

How is customer conservation specifically addressed? The PSCs expressly invoke the Northwest Power Act priority for conservation in the following sections:

- Utility PSC, Section 5, "Agreement as to Bonneville's Decision in Acquiring Resources to Serve Load," acknowledges the priority that BPA must give to conservation. It also provides that the customer agrees to use its best efforts to serve its load growth by acquiring resources or by developing them for BPA acquisition in accordance with conservation and other resource priorities of the Northwest Power Act.

- GCP 44 "Resource Acquisition and Management," which applies to all three types of generic contracts, acknowledges BPA's obligations under Section 6 of the Northwest Power Act to abide by Northwest Power Act priority for conservation and other resources.

- In addition, GCP 45, "Cooperation with Regional Council," provides for the parties to negotiate amendments to the PSCs if necessary to permit the Council's Plan or Fish and Wildlife Program to be effective. This provision has never been invoked. It is not known whether this provision has had an effect on voluntary conservation participation by BPA customers.

Disincentives for customer failure to implement conservation are included in several places:

- GCP 8(d), "Conservation Surcharge," applies to all three types of generic contracts. It sets forth the procedures for application of the conservation surcharge called for by the Northwest Power Act.

- Utility PSC Section 7, "Allocations in Event of Insufficiency," limits a customer's access to excess energy in the allocations methodology if that customer declined to implement cost-effective BPA conservation or to implement its own conservation programs.

Various provisions assure that conservation will be specifically identified:

- Utility PSC, section 3(b), definition of "Actual Firm Load" provided that the calculation will reflect decreases due to conservation by BPA or customer programs.

- Section 11(b)(4)(B), "Compensation in Event of Regional Curtailment," provides that conservation be identified in determining if customer load growth is greater than resources developed for sale to BPA. If customer load growth is greater than the resources, including conservation, that it has developed to serve such load growth, the benefit of BPA compensation in event of curtailment will be reduced.

- Section 17(b)(6), which addresses the Contracted Requirements method of purchasing, provides that Contracted Requirements purchasers must revise their Estimated Firm Loads to reflect all conservation measures and direct application renewable resources if it appears that BPA would have to acquire a resource to serve its customers. This requires that conservation be identified to reduce BPA's contractual obligation to serve load and to defer a possible resource acquisition.

Do the differences in accounting for generating resources and conservation constitute a disincentive? The foregoing analysis of contract provisions indicates that the PSCs generally provide an incentive for customer implementation of conservation. The PSCs do not impair the influence of other important ecomonic and political incentives for conservation.

Since the passage of the Northwest Power Act in 1980, the level of sophistication and interest in conservation as a resource has increased in the region. Utilities are pursuing conservation as the regional surplus dwindles and as some utilities begin to face the choice of building generating resources, purchasing conservation, or placing load on BPA. Many jurisdictions in the region are adopting programs to support Model Conservation Standards.

State regulatory agencies in Washington and Oregon recently passed least-cost planning regulations that dictate the inclusion of conservation in least-cost resource plans. The Oregon Public Utility Commission in particular is considering ways to reward IOUs financially for reducing demand through conservation rather than for increased sales that could require increased generation. The Washington Utilities and Transportation Commission has recently adopted procedures to "decouple" rate regulation from sales volume to remove regulatory disincentives for conservation investments.

Conservation Activities of Preference Customers. In general, most preference customers have participated in conservation programs sponsored by BPA in spite of the lack of a contract mandate. The funding and program support provided by BPA has been a sufficient incentive for these utilities to acquire conservation in their service territories. A few preference customers have augmented BPA's residential weatherization programs with funding of their own. For these reasons, the alternative is not expected to significantly effect BPA's preference customers.

Conservation Activities by Private Utilities. The regional private utilities generally do not participate in BPA's programs. BPA's Cost-Sharing Principles (Final Cost Sharing Principles, January 1985) state that BPA will not fund conservation for private utilities in the region unless they purchase at least 1 percent of their electricity needs from BPA. The principles are intended to ensure that BPA benefits from the conservation that helps BPA meet its load obligations. Also, program costs are covered by power sales revenues. Since most IOU's have not placed requirements load on BPA, they have generally not participated in BPA's conservation programs.

During the past decade, some regional IOUs have invested in their own conservation programs or funded programs designed by BPA for its preference customers, such as the Super Good Cents program (see the Council's issue paper Assessment of Regional Progress toward Conservation Capability Building, March 13, 1989). All IOUs in the region have been operating residential weatherization programs for nearly 10 years. In general, however, the IOUs have pursued less conservation in the commercial and industrial sectors.

In view of the increased adoption by Northwest utility regulatory commissions of least-cost planning principles and the adoption by States of energy-efficient building codes based on the Northwest Power Planning Council's Model Conservation Standards, it is assumed that conservation will be promoted as a good business decision. Investigation by public utility commissions into removing regulatory barriers to conservation also supports a projection that IOUs will acquire cost-effective conservation. For these reasons, no significant impacts on IOU conservation are expected from the alternative.

2.2. Conservation Transfers Facilitated

2.2.1. Method of Analysis

The analysis qualitatively examines the effects of removing an existing power sales contract prohibition against resale of firm requirements power supplied by BPA for the purpose of facilitating conservation transfers. Resale of BPA requirements power would then be allowed for conservation transfers in the region. The analysis addresses whether allowing wholesale resale of BPA requirements power would affect the amount of conservation transferred. It also generally addresses the effect of conservation transfers on the amount of conservation achieved in the region. Quantitative analysis was not prepared because there is little data on the amount of "transferable" conservation available and because such amounts are probably highly sensitive to several factors discussed below.

2.2.2. Environmental Effects

Under the No Action Alternative, existing PSCs prohibit resale of firm requirements power, but conservation transfers which do not involve the resale of firm requirements power are not affected. Under Alternative 2.2, the PSCs would no longer prohibit resale of firm requirements power for conservation transfers.

2.2.2.1. Effects of Conservation Transfers on Amount of Conservation

To determine whether allowing resale of Federal power would have a significant effect on conservation transfers, it is helpful to explain the structure of conservation transfers in general. Whether conservation transfers of any type would result in significantly more conservation in the Pacific Northwest depends on several factors: need for resources; BPA's funding levels for conservation acquisition; the new resource needs of other Pacific Northwest utilities, chiefly IOUs (but conceivably also preference utilities); and the costs of new resources. The following scenarios show that the amounts of available conservation transfers could be significant in some fact situations and insignificant in others.

Scenario 1. Under Scenario 1, conservation transfers could significantly increase the amount of conservation achieved in the region. In this scenario, BPA has a large energy surplus but a reduced amount of funds available for conservation acquisition. In this scenario, some Pacific Northwest utilities need to acquire resources currently or in the near future. These utilities do not wish to place long-term requirements load on BPA (consistent with current practices by IOUs). Generating resource costs are relatively high for new acquisitions. Due to reduced BPA funding levels, BPA customers who are qualified to participate in BPA conservation programs have less access than they would like. Conservation transfers offer these utilities a way to finance conservation measures and a potential source of revenue to defray conservation costs borne by ratepayers. The power transferred as a result of the additional conservation allows the purchasing utility to defer acquisition of a higher-cost generating resource.

Scenario 2. Under Scenario 2, conservation transfers help to develop a certain amount of additional conservation, but less than Scenario 1. Less additional conservation is possible in Scenario 2 because BPA needs to acquire new resources to serve its firm loads and has increased its conservation budget levels and programs to acquire cost-effective conservation. Since BPA is providing funding, utilities would be most likely to use such funding. If it is assumed that IOUs do not place long-term load on BPA but do need to acquire resources, it is possible that conservation transfers could develop a certain amount of conservation. Such conservation would not be cost-effective for BPA, but might be cost-effective for some IOUs if their avoided cost of new resources was higher than BPA's.

Scenario 3. Under Scenario 3, the conservation transfer mechanism would not develop additional conservation because BPA needs to acquire new resources, has sufficient funds available to offer programs sufficient to capture all cost-effective conservation, and IOUs place their long-term firm load requirements on BPA. Therefore, BPA would develop available and cost-effective conservation on a regional basis.

Under present conditions, with BPA moving from a surplus condition to resource acquisition, and with IOU's placing little of their load on BPA, the most probable of the three scenarios is Scenario 2.

2.2.2.2. Effect of Resale of Federal Power

Under the alternative, conservation transfers could involve a resale of the preference customer entitlement to requirements power. This type of transfer can have additional, different effects than conservation transfers without resale of this entitlement. Although conservation transfers can be generally beneficial to all parties, the resale of entitlement to BPA requirements power has adverse public policy results.

The economics of conservation transfers indicates that the ability of preference customers to resell Federal power from conservation transfers might make conservation transfers somewhat more attractive. A conservation transfer probably could not be successfully negotiated unless the transfer power comes from a source with assured long-term availability and relatively low, predictable costs compared to alternate resource acquisitions. The BPA firm requirements power supplied to preference customers meets this test better than some alternatives, such as surplus power supplemented by future backup resources.

However, resale of Federal power is strictly limited by statute to prevent abuse and guarantee availability to public users. Significant public policy disadvantages argue against removal of the current prohibition against resale of Federal power. For example:

- The Northwest Power Act's preservation of the PF rate pool for preference customers and residential exchange loads would be circumvented to the extent the transferred power was priced based on the PF rate and sold to non-preference or residential exchange loads. (It would be priced based on the relationship between conservation costs, transferee avoided costs, and perhaps PF rates.)

- The Northwest Power Act's preservation of priority for preference customers to the Federal base system resources might be circumvented: BPA would be obligated to supply contractual requirements power to a preference customer for transfer to an IOU.

- The Bonneville Project Act's requirement of 5-year callback on sales to IOUs, if power is needed for preference customer firm loads, might be circumvented.

- The Bonneville Project Act's limitation on resale of Federal power by private parties which do not sell to the general public might be impaired.

- BPA's intent to assure that the savings from the conservation programs involved in the transfer are equal in amount and duration to the power transferred might be circumvented.

- BPA's access to some cost-effective conservation could be lost, since utilities would have an incentive to "cream-skim" (i.e., take the lowest-cost conservation measures, rather than include higher-cost measures in programs which, as a whole, would be cost-effective) in order to maximize the gain from the transfer.

2.2.2.3. Conservation Transfers Facilitated Without Resale of Federal Power

Conservation transfers can be designed without necessitating resale of firm requirements power thereby avoiding the public policy disadvantages of resale of Federal power. BPA is pursuing a conservation transfers pilot program utilizing surplus firm power to explore one alternate mechanism. Conservation transfers may also be accomplished using utility-owned resources.

CATEGORY 3. RESOURCE PLANNING/DEVELOPMENT

3.1. BPA Load Placement Certainty

3.1.1. Method of Analysis

The analysis compares the effects of longer or shorter notice periods for placement of firm load on BPA, in view of the times needed to develop various resources. This analysis is done qualitatively because the major change is in the probabilities that certain types of resources will be developed in a certain sequence. The actual amounts of resources developed will tend to be the same under the alternative as under the Base Case, and will be highly sensitive to load growth, rather than contract provisions.

3.1.2. Environmental Effects

The analysis examines the likely resource development effects of the length of notice given BPA by customers to signal a load increase or decrease. Under the existing contracts, customers must generally give seven years notice. For the alternative it was assumed that they must give 10 years notice. The analysis test whether the extra 3 years of notice would affect the types of resources developed, given the lead times for such resources. The alternative could change the probability that resources are developed by utilities versus BPA and, therefore, could affect the types of resources developed.

3.1.2.1. Lead Times for Types of Resources

The analysis shows that the effect of a longer notice period is unpredictable. On one hand, it could increase the chance that BPA could complete WNP-1 and -3 or develop coal plants, if necessary. It would not affect other types of resources because of their shorter lead times. On the other hand, by increasing risk to the customer, it could decrease the likelihood of utilities placing load on BPA (see section 3.1.2.2. below).

Of the resource types BPA examined during its long-term planning, only coal plants have lead times longer than 7 years. Therefore, the 10-year notice alternative would change the types of resources in the stack only if load growth had to be met by coal resources rather than cost-effective conservation or other resources. This would occur only if coal costs were less than the costs of the marginal conservation or other resource measures needed to meet projected loads.

Ten-year notice of load placement would give BPA 3 extra years to decide whether it would need to complete WNP-1 and -3. BPA currently assumes in its planning process that the last year in which a decision could be made to resume construction of the plants is 2000. Therefore, if load growth appeared possible for the eighth, ninth, or tenth years of the planning horizon, BPA could decide to complete construction if BPA received such notice by the year 2000.

3.1.2.2. Customer Risk

A 10-year notice period could increase BPA's customers' supply risk: in effect, a 10-year notice period is equivalent to a resource with a 10-year lead time. Many utilities favor power from independent producers, Public Utility Regulatory Policies Act (PURPA) qualifying facilities, demand side management, and import purchase or exchange contracts. These resources can have relatively small unit sizes and short lead times. Utilities with these options will buy from BPA only if BPA offers competitive terms and conditions.

Because of power supply competition, an increase in a customer's risk due to lengthening the notice period by 3 years could decrease the customer's willingness to place load on BPA. The impacts would be similar to Alternative 3.2 assuming 0 percent IOU load placement on BPA. This influence could offset the influence of 10-year notice on coal plant or WNP development.

3.2. BPA as Regional Supplier

3.2.1. Method of Analysis

This analysis consists of a summary of a BPA study done for the 1987 draft Resource Strategy, qualitatively modified in light of modern conditions. Whereas the original study showed certain significant changes in the region's expected resource stack, the current conclusion is that the differences would be much smaller.

The 1987 study attempted to quantify the benefits of BPA supplying all resources necessary to serve the region's load growth. At the time, BPA was struggling with the appropriate resource strategy to adopt given that IOU customers were projecting no purchases from BPA during the 7-year planning horizon under the PSCs. The original study was done using the Decision Analysis Model to estimate the effects on regional system costs and benefits, wholesale power rates, and the types and timing of new resource acquisitions. It compared a case with BPA as the sole regional resource supplier to another case in which IOUs did not purchase firm power from BPA for their load growth. In fact, at least some of BPA's preference customers may consider developing their own future resources rather than purchasing from BPA though the study assumed that BPA would serve all preference customer load growth.

3.2.2. Environmental Effects

The 1987 study found significant economic benefits from BPA acting as the regional resource supplier based on five major factors. First, the then-existing BPA surplus could defer resource investments by Pacific Northwest utilities. Second, BPA could more efficiently integrate large resources coming on line into the region's total loads. Third, BPA has access to relatively low-cost nuclear power from WNP-1 and -3, whereas IOU resource stacks contained higher cost coal plants. (For this analysis, WNP-1 and -3 were assumed not to be needed until after 2000, although the need could occur earlier. Some of the benefits of BPA as regional supplier would disappear if WNP-1 and -3 were no longer assumed to be available when needed.) Fourth, if

BPA were the regional resource provider, it could enhance the region's ability to use low-cost conservation from preference customer systems to meet regional needs. (See further discussion on this in Alternative 2.2 on conservation transfers.) And fifth, lower-cost financing might be available to BPA or through a cooperative arrangement involving preference customers than would be available to IOUs (although there could be difficulties with tax-free financing).

The study results showed significant changes in likely regional resource development, shown in Table 3.2.1. There was an estimated net benefit to the Pacific Northwest as a whole of approximately $2 billion.

Table 3.2.1

Effects of Alternative 3.2

Change in Net Resource Additions Compared to Base Case
by Type and by Period a/
(Cumulative Average MW)

Resource Type	Years			
	1995	2000	2005	2010
Coal	-367	-1000	-984	-1224
Nuclear	+138	+519	+542	+542
Combustion Turbines	-73	+2	+37	+96
Renewables b/	-166	-108	-77	+19
Conservation	+40	+70	+96	+114
Net Resource Adds	-428	-517	-386	-453

a/ Figures in table are average megawatts of new resource acquisitions for the alternative case. Because of different capacity factors for plants within each resource category, it is not possible to specify installed capacity in this table. Also, these values represent expected values over 100 games. Therefore, they represent the average of situations ranging between zero and several thousand megawatts of resources acquired.

b/ Renewable resources included here are small hydro and cogeneration.

The additional 542 aMW of nuclear power built in the region by 2010 represents the expected amount of WNP-1 and -3 that would be built to meet regional load growth in the alternative case. This figure translates to an additional two-thirds of a plant compared to the amount that would be added in the IOU 0 percent case.

Generation from combustion turbines would increase slightly, despite an initial decline, because CTs can be acquired more economically than coal plants. The average amount of new CTs by 2010 is just under 100 MW, an insignificant amount.

Conservation acquisitions would be slightly higher in all periods, increasing to a 114 MW difference by 2010. A greater amount of conservation from public utility service areas would be cost-effective since it could be used to meet IOU load growth and would cost less than coal.

Based on the older study, by 2010, total resource acquisitions in the region would be 453 MW lower than the base case if BPA were to act as regional supplier. This amount is roughly equivalent to the output of the Boardman plant. Most of that reduction would be achieved early in the study period because BPA could meet IOU deficits with the Federal firm surplus and could match plant size closely to supply needs. The greatest part of the difference is the large reduction in coal acquisitions, tempered by the increases in both nuclear power and conservation acquisitions.

However, these results must be qualified in light of current conditions. This alternative has environmental implications in that it changes the likelihood that BPA rather than utilities will acquire resources to serve the region's load growth. The types of resources acquired may therefore differ to the extent that different resources are available to BPA versus other entities. Recent developments in the past 2 or 3 years have probably increased the similarity between resources which may be developed by BPA and utilities. These developments include the decline of BPA's and the region's firm energy surplus, the use of least-cost planning processes by State regulators and utilities, and the trend towards competitive bidding for future resources, and the declining importance of large thermal projects as compared to smaller resources, transmission linkages and purchase agreements. The recently-developing trends toward utility least-cost planning processes and resource acquisition bidding procedures may influence the types of resources developed by utilities. For example, development of coal plants that the Decision Analysis Model study assumes may be decreased and deferred farther into the future.

However, some relatively low cost resources may be more likely to be developed by BPA than by utilities. These include, but are not limited to, completion of WNP-1 and -3; coordination of the Columbia River power system with Canada; and the ability to firm the nonfirm power produced by BPA's hydro system. Therefore, an alternative that shifts resource development from utilities to BPA may increase the potential that BPA will complete existing nuclear plants and may advance the development of "firming" nonfirm energy from Federal hydro projects. An alternative that shifts resource development from BPA to the utilities may increase the development of coal plants or qualifying facilities under the PURPA and other independent power facilities. In addition, the types of resources acquired by BPA may differ from utility acquisitions due to BPA's statutory obligation to acquire cost-effective resources in accordance with the priorities and environmental cost considerations imposed by the Northwest Power Act.

It is worth noting that some of the benefits of regional cooperation can be realized by means other than having BPA act as the sole regional supplier of new resources. Conservation transfers, which BPA is now exploring, are one example. It is also possible that least-cost planning procedures implemented by State public utility commissions may increase utility investment in conservation and renewable resources.

3.3. Customer Planning on other than Critical Water Basis

3.3.1. Method of Analysis. The analysis is a qualitative evaluation of the effects of the PSCs and the Coordination Agreement on customer planning criteria.

3.3.2. Environmental Effects

The effect of the alternative would be an unmeasurable, but probably small, decrease in the likelihood that Actual Computed Requirements utilities will invest in sufficient resources to serve their firm loads based on critical water planning criteria. Such customers generally are preference customers with significant generating resources.

As explained in the Chapter 2 description of the No Action Alternative to Alternative 3.3, the PSCs adopt the critical water planning basis from the Coordination Agreement. The Coordination Agreement applies this criterion to the calculation of the coordinated system's Firm Energy Load Carrying Capability and the FELCCs of utilities that are parties to the Agreement. (See Appendix C for a description of these procedures.) The Coordination Agreement establishes the capabilities of existing resources on a critical water basis; it does not require parties to invest in resources sufficient to serve their firm loads on that basis. A Coordination Agreement party could elect, at its own risk, not to acquire sufficient resources based on critical period planning. However, the firm capabilities of that party's existing hydro resources covered by the Coordination Agreement would continue to be calculated based on critical water. The utility would show a deficit of planned firm resources.

As explained in Chapter 2, the existing power sales contract provisions change this situation by imposing an additional disincentive upon the Actual Computed Requirements customer. The disincentive is the risk of having to pay BPA a charge based on the amount of firm power the customer had a right to take. It considers the utility's own Assured Capability calculated in accordance with critical water criteria.

If the disincentive were removed, Actual Computed Requirements customers would be in the same position as Contracted Requirement purchasers, the IOUs. Most IOUs use critical water planning criteria despite the absence of a disincentive from BPA. (Puget Sound Power & Light has been deficient in firm resources on a planning basis based on critical water criteria. The Idaho Power Company is not a member of the Coordination Agreement and uses average water as its planning basis.) Based on the actual practices of the other parties to the Coordination Agreement, no significant effects are expected as a result of this alternative.

3.4. Improved In Lieu Provisions

3.4.1. Method of Analysis

The analysis is a qualitative evaluation of the changes expected if BPA could make purchases (in lieu of exchanges under the Residential Purchase and Sale agreements) on shorter notice than the 7-year notice currently required.

3.4.2. Environmental Effects

Environmental effects are considered to be insignificant because there will not be real changes in the types or timing of generating resources developed. The following discussion shows that the major change would be to advance or delay by a few years BPA's need to develop resources. The potential financial effect on the costs of the residential exchange program and the costs of the exchanging utility would not have a predictable socioeconomic impact.

3.4.2.1. Environmental Implications of No Action

The residential exchange program is an accounting transaction without significant environmental implications.

As described briefly in Chapter 2, if BPA proposed an in-lieu purchase, the utility could elect to lower its Average System Cost to equal the cost of the in-lieu resource.

If the utility did not so elect, BPA would use its own surplus power or purchase the lower-cost resource in lieu of purchasing from that utility. BPA would continue to be obligated to deliver power to the participating utility at the applicable PF rate to serve the utility's exchange loads. The actual delivery of in-lieu power would cause the exchange to become more than merely an accounting transaction: the power "delivered" by BPA would no longer be "cancelled out" by an equal and opposite "delivery" by the utility. The utility would retain the amount of power it formerly exchanged, marketing it to its firm loads or to other customers to recover its costs.

If BPA made a purchase in lieu of an exchange under current notice provisions (and the utility did not exercise its option to reduce its Average System Cost), the effects would be primarily economic. For example, the exchange payment to the participating utility would be eliminated. The total costs of the exchange borne by BPA's ratepayers would be decreased. The utility could benefit, or at least offset the subsidy reduction, if it could sell its former exchange power at an advantageous price.

There are some conceivable environmental implications of an in-lieu transaction:

1. If BPA used its own surplus power as the in-lieu purchase, BPA would be committed to continue that course of action for at least 12 years, since BPA must give seven years notice and the purchase must be for at least five years. If that amount of surplus turned out to be unavailable, BPA would have to acquire resources to continue serving the participating utility.

2. Issues remain unsettled regarding the delivery of residential exchange power to the utility system in the event of an in lieu purchase, such as shape of schedules and delivery points. Schedule shaping could affect the operation of BPA's resources, although this could be avoided by negotiation of appropriate scheduling provisions. The negotiation of delivery points could necessitate construction or upgrade of facilities.

3. Actual operation of a resource purchased in lieu of an exchange would have environmental implications, depending on the type of resource, including potential economic displacement of the resource.

3.4.2.2. Environmental Implications of Alternative

If the notice period for in-lieu purchases was shorter than the current 7 years, the first environmental implication described above would be affected but the second and third would not. If BPA used its surplus as an in-lieu resource, the shorter notice period would reduce the risk of need to acquire a resource to back up the forecasted surplus.

From the exchanging utility's viewpoint, shortening the in-lieu notice period would increase the risk of acquiring resources. If a utility received an in-lieu notice from BPA while acquiring or constructing a generating resource, the resource could become surplus to the utility's system. Delaying completion of the resource would delay the utility's return on its investment. The utility could complete the resource and sell the output, with risk that the price would not recover the full cost of the resource. Similarly, if the in-lieu power displaces an existing resource, the utility may not be able to sell the power at a price that recovers the cost of the displaced resource.

The effects listed above could lead to lower returns on the investment of the utility's shareholders or higher power rates for the utility's customers.

Reduced exchange cost resulting from an in-lieu purchase could reduce the PF rate, increasing the BPA subsidy for the remaining exchange loads. This impact would not eliminate the direct benefits to BPA of exercising in-lieu provisions.

Because exchange payments are required to be passed directly to a utility's residential and small farm customers, a change in the payment alters retail rates. The effects on those consumers or on the utility's load would depend on the magnitude of the increase.

3.5. Shorter Contract Terms

3.5.1. Method of Analysis

This analysis is primarily qualitative. The impacts are dependent upon the subjective responses of BPA's customers to the uncertainty imposed by a 10-year term for their firm requirements contracts. Effects on utility customers are assessed qualitatively because the changes would be based on concepts such as the customers' legal rights to requirements service, current utility notices of load placement on BPA, and information available regarding utility long-term power supply strategies.

Effects on DSIs are discussed qualitatively considering the effects of increased power supply risk on business decisions and the availability of more secure alternatives. The DSI/Decision Analysis Model was used to examine a worst-case scenario in which the DSIs would buy power from Pacific Northwest retail utilities rather than directly from BPA. In that scenario, BPA would continue to serve the DSI load through the local utility; however, the DSIs would pay a rate based on the costs of new resources rather than BPA's wholesale power rate. The results of the analysis are highly dependent on several factors: the rate charged by the utility, the world market price of aluminum, and the quality of service provided to the industry. Qualitative discussion describes how the impacts could vary within a large range.

3.5.2. Environmental Effects

The environmental implications of the alternative arise primarily from changes in the decisions by various parties to develop resources. BPA resource development obligations would decrease if customers responded to the shorter contract term by shifting their reliance from BPA to options they perceived as more certain long-term sources of supply. As discussed under Alternative 3.1, Background on Differences Between BPA and Non-BPA Resource Planning and Development, there may be significant differences in the types of resources developed by BPA and Pacific Northwest utilities, although regulatory trends may foster similar resources choices for both. In addition, changes in resource needs could occur if power usage was decreased in response to price elasticity or load management programs.

3.5.2.1. Load Placement on BPA

3.5.2.1.1. Utility Customers

Expected load placement by IOUs would be the same as under the Base Case. IOUs currently project no firm requirements purchases from BPA.

Preference customers that own and operate significant resources of their own might be discouraged from placing further load on BPA, although this would not necessarily be significantly different from the status quo. The preference customer utilities in the Public Generating Pool (PGP), for example, are currently investigating alternate resources which provide increased independence from BPA. PGP utilities would, however, retain preference rights to Federal base system and other BPA resources and could be expected to make use of them. The result might be the same expected load placement on BPA despite length of contract term.

Preference customers without significant generating resources probably would not change their resource strategies significantly. They would be expected to continue to rely on their preference rights to Federal base system resources and place most or all their load growth on BPA.

3.5.2.1.2. DSI Customers

If BPA PSCs had shortened terms of 10 years, DSIs could be expected to be increasingly interested in the following service options:

Service from a local utility. Some of the effects of this option are described below under the discussion of DSIs as NLSL of utilities. If the utility was a generating utility with surplus power it could use to serve a DSI, a result could be decreased competition in the surplus market. BPA's revenues from surplus sales could increase, potentially defraying the loss of DSI revenue.

If BPA provided service to the DSI load indirectly through the retail utility, the load might be served 100 percent firm or might be fully or partially interruptible by the utility. The region's need for firm resources could be increased by the amount of the DSI First Quartile and the reserves provided by BPA's current DSI restriction rights. (See Alternative 4.4 for a description of the effects of loss of DSI reserves.) On the other hand, if the contract between the new utility supplier and BPA so provided, and depending on the utility's restriction rights, BPA might have access to additional reserves. The utility's restriction rights may be the same as or differ from those BPA now enjoys under its contracts.

Service from another utility. This option assumes that the local utility would wheel power across its system from the selling utility to the DSI. Legal issues about state-defined service area boundaries might require resolution. If BPA provided wheeling service, BPA's wheeling revenue would be increased. Transmission system costs could eventually increase, as well. If

DSIs purchased wholesale power on the open market, the number of entities competing for the same power would be increased. Increased competition among purchasers in the Pacific Northwest would increase market prices, especially during a period of regional deficit.

Self-generation. DSIs could elect to increase their reliance on self-generation. Experience elsewhere in the nation has indicated that self-generation can lead to redundant development of resources if price and other terms make utility service unattractive to the industrial customer. Resource development for self-generation need not be redundant if the resources developed would otherwise be lost or if they are coordinated and integrated so as to defer utility resource development. DSI cogeneration has the potential for higher fuel efficiency than alternative resources. Some U.S. utilities have forestalled development of unneeded resources by offering negotiated rates and back-up charges. Resources developed for self-generation could increase competition for the regional supplies of oil, gas, coal, or other fuels, raising market prices.

3.5.2.1.3. DSIs as NLSLs

A DSI served by a regional utility would be subject to designation as a "new NLSL" if its load was in excess of 10 MW. Almost all of the 14 active DSIs would become NLSL.

Loads of NLSL/DSIs served by metered requirements preference customers of BPA likely would be served by purchases from BPA at the NR rate, the cost of which would be passed on to the industrial user. Those in computed requirements customers' service areas might be served by non-BPA resources at retail rates based on the costs of such resources, if the resources used to serve the NLSL/DSIs were dedicated to those loads (i.e., removed from the serving utility's Firm Resources). Provisions of the existing utility PSCs allow the utility to sell specific resources to the NLSLs at a rate based on the costs of those resources. The NLSL/DSI's rate also would be set considering the impact of the load on the utility's cost of power production and acquisition. The contract between the utility and the NLSL would establish the quality of service to the plant. The utility's remaining firm load would be served by purchases from BPA as needed.

If the local utility needed to purchase power from BPA in order to serve the DSI load, BPA could require as much as a 7-year notice of an increase in utility load pursuant to section 9(b)(2) of the utility PSC. The notice period would allow BPA time to arrange to meet its resource acquisition obligations, but would require the utility to make a resource available to continue service to the industrial consumer.

3.5.2.2. DSI Effects

3.5.2.2.1. Effects of Increased Rates. The effect on a DSI economic viability of changing suppliers would be determined primarily by the quality of service provided and the rates charged by the power supplier. A higher rate, such as one based on the NR rate, would increase the DSIs' costs of production; rates to other BPA customers might drop as a result. Other possible results include reduced aluminum smelter loads, employment, and net benefits to the region. In the years 2000-2015, DSI loads could decrease by 13-33 percent under the alternative, depending on the rate paid and the price of aluminum. Direct employment and secondary employment also could decline. Higher rates would also increase the attractiveness of lower-cost power supply alternatives such as cogeneration. See BPA's DSI Options Study and EIS for a detailed description of effects related to the economic viability of DSIs.

3.5.2.2.2. Increased Risk. A shorter contract term would increase the DSIs' power supply risk. Higher perceived risk could discourage investment in capital improvements, reducing the competitiveness of Pacific Northwest plants and further encouraging aluminum companies to treat their Pacific Northwest plants as swing plants. It could also increase or accelerate plant closures.

The quality of any investment opportunity is a function of: (1) The expected return on the investment; (2) the expected life of the investment; (3) the distribution of the return on investment over the life of the investment; and (4) the risk associated with the expected return on the investment. Most business investments are weighed against a base return that is available on investments with very low associated risk. The risk of an investment dictates the level of return necessary to attract capital for the investment. As the perception of the level of risk increases, the investor will require a greater return on the investment, or the investment is simply not made.

Both the DSIs and utilities are capital-intensive industries. Capital-intensive investments require long lead times for planning and construction and the commitment of large amounts of capital before any return on investment is realized. The average useful life of these assets is long. Interest costs associated with these investments cannot be avoided even if the project is not operated.

Given the nature of these investments, there could be two adverse impacts of reducing the term of the PSCs from 20 years to 10 years. First, the cost of the investment must be spread over 10 years rather than 20 years, or an economic alternate source of power must be assumed to be available as a replacement. The cost of an investment to make production more efficient is incurred years in advance of any return on the investment. Once the capital costs are incurred, they cannot be avoided even if the sales price the industry can get for its commodity does not recover the costs. The shorter contract term will increase the investor's perception of risk that a reasonably priced supply of power that permits plant operation will not be available. If power is not available, no return on investment will be earned and costs will not be recovered.

Second, the investor will perceive a greater risk of low product prices than of higher product prices. Over a longer investment horizon there is a statistically greater chance that the business cycles will balance out. The higher perceived risks will cause the investor to require a higher expected rate of return in order to make the investment.

The risk of recovering the cost of a long-term investment over the few remaining years of a PSC in a volatile commodity market would require a relatively high rate of return. It may be that the return required to attract capital under these conditions is so high that no investment would be made.

The uncertainty of the continued operation could negatively affect the quality of labor attracted to the industry and the contract terms for other services and materials required for continued production.

CATEGORY 4. QUALITY OF SERVICE AS A RESOURCE CHOICE

4.1. Increase First Quartile-Type Interruptibility (Case A and B)

4.1.1. Method of Analysis

The SAM was used to assess power system operational effects, frequency of interruption of DSI loads, and changes in resource costs due to conversion of DSI load from firm service to First Quartile-type service. Impacts on fish and wildlife were assessed by the method described for Alternative 1.2. Impacts on DSI economic viability due to frequency of interruptions and rate effects were assessed qualitatively. Because, in this alternative, we assume that the increased interruptibility also could come from non-DSI loads, impacts on non-DSI loads that might provide such interruptibility also are addressed qualitatively. BPA has not assessed whether the Case A and Case B amounts of increased interruptibility are actually available from non-DSI loads.

It should be noted that this alternative has some significant effects on resource operations, largely because of the time that the new quality of service is assumed to be implemented. A large amount of firm load is converted to lesser quality of service all at once, creating a firm surplus. The resulting impacts could be lessened or avoided if the quality of service switch were phased in.

This EIS does not contain assumptions concerning the rate adjustments that would probably accompany a change in the contract provisions on quality of service. Therefore, these results may indicate more adverse effects on DSI customers and greater economic benefits to other customers than would be expected under a negotiated contract change addressing both rates and quality of service and realistically reflecting the give and take which would be required to reach agreement on such matters. If a result of this EIS is to pursue contract changes, these tradeoffs, and specifically changes in rates, will be evaluated in the Stage Two process. (See also Chapter 3, Overview of Category 4, Quality of Service Issues.)

System Analysis Model Assumptions. Under No Action, the DSI first quartile load is served with nonfirm energy and borrowing techniques. Firm resources are not acquired for this load. The other three quartiles and all other regional loads are firm.

For Case A, which assumes 50 percent DSI interruptibility, half of the DSI load is served in the same manner as the first quartile. The remaining half is served as firm load. Since the third quartile is still available for backup if the hydro system does not refill, then shift, provisional, and flexibility will be allowed at the current levels.

For Case B, assuming 100 percent DSI interruptibility, no DSI load is considered to be firm for resource planning purposes. All DSI load will be served only by nonfirm energy, surplus firm energy, and purchases from BC Hydro when available. Shift, provisional, and flexibility energy are not used to serve the DSI load in this case.

Separate runs of the Least Cost Mix Model were made for each case to obtain assumed resource additions, since each has a different amount of firm load. The amount of additional firm load assumed to be interruptible for analysis under these alternatives is not constant over time. In the SAM modeling, the amount of assumed interruptible load was expressed as a percentage of the forecasted DSI load. Since the amount of forecasted load varies over time, the amount of assumed interruptible load varies over time. (See Appendix G-1 for amounts of interruptible load for each year of the study.) Case A assumes that the additional interruptible load (25 percent of the total DSI load) is 749 aMW initially (1989), with 642 aMW in the last year of the analysis (2008). Case B assumes that the entire DSI load is interruptible: 2245 aMW of additional interruptible load in 1989 and 1924 aMW in 2008. If high Northwest load growth is assumed, the additional interruptible load would be 817 aMW in 1989 and 831 aMW in 2008 for Case A, and 2452 aMW in 1989 and 2494 aMW in 2008 for Case B.

4.1.2. Environmental Effects--Case A--50 Percent

The environmental implications of this alternative stem in part from changes in operations due to a decrease in firm load that BPA must plan to serve. The resulting surplus firm power tends to be shaped for surplus marketing purposes into the period from August through October. If the increased interruptibility involved non-DSI loads that are currently firm, other environmental implications could arise connected to the specific loads to be interrupted.

4.1.2.1. Future Resource Development

The amount of firm load for which BPA is obligated to plan and secure resources is decreased from current assumptions such that new BPA resource additions can be deferred. The results for Case A (see Tables in Appendix H-9) show that only one new nuclear plant was required to be added, in 2003, to meet firm loads (assuming expected gas price and Northwest and Southwest load). Under No Action with the same assumptions, two nuclear plants would be projected to be added, one in 2000 and one in 2004.

The resource stack used is the same as that resulting from the 1988 Resource Program, which considers completion of WNP-1 and -3 as the lowest-cost major resources available. The model adds these nuclear resources when a large resource is needed to meet load growth. Equivalent amounts of other resources could be added instead of WNP-1 and -3 if the economics were favorable or if completion of the two nuclear plants became infeasible. Resource additions might then occur at slightly different times, since the generating capacity of non-nuclear resources is less on a per-unit or per-plant basis. For example, if the model shows a nuclear plant being added in 2003, it might have shown a coal-fired unit being added in 2002 and another in 2004 if the resource stack used had coal-fired generation as the first type of resources to be added.

The region is able to defer acquisition of small amounts of other resources in Case A. In Case A, 765 aMW of conservation was added through the course of the study period, 1989 through 2008; under No Action, 781 aMW of conservation was added over the same period. Three hundred twenty-four aMW of small resources (e.g., small hydro, cogeneration, and wind) were added in both No Action and Case A, but they were added later under Case A. In Case A, the small resources all were added by the end of the year 2000, but with No Action, they were added by the end of 1998.

No additional combustion turbine facilities were developed.

There also was no change in the amounts of purchases from outside the Pacific Northwest. In order to achieve load/resource balance, the model assumes short-term acquisitions of energy from other utility systems. These could occur when a major resource cannot be brought on line in time to meet load or when the resource deficit is small or short enough not to justify bringing on a major resource. With expected loads and gas prices, no such acquisitions were needed under either the No Action Alternative or Case A.

In the high load growth scenario, the effect of the alternative is to defer acquisition of coal plant priced resources and avoid moderate amounts of off-system purchases.

In the event Northwest load growth turns out to be high, two nuclear plants are projected to come on line by 1997 in both the No Action Alternative and Case A. In the Northwest high load sensitivity case, coal-fired generating units would be added to meet load beginning in 1999 under both No Action and Case A, and additional coal plants are added each year through the end of the modeled period. At that point, in 2008, 6928 aMW of additional coal-fired generating capability was added in the No Action Alternative versus 6113 aMW with Case A. Thus, two fewer coal-fired generating units of typical capacity and plant factor would be required assuming Case A was implemented.

There was little change in the amount of small resources and conservation between Case A and No Action. With high Northwest load growth, conservation is added in the same time frame under either Case A or the No Action Alternative. In the small resources category, 939 aMW of renewables are added over the course of the study under Case A and 957 aMW under the No Action Alternative. Again, no additional combustion turbine facilities were added.

With high Northwest loads, short-term energy acquisitions from other utility systems are used from 1989 through 1998 to avoid a deficit in both the No Action Alternative and Case A. However, substantially smaller amounts of acquisitions were required with Case A.

Appendix F discusses the generic impacts of conservation and cogeneration and the operation and development of new nuclear and coal-fired generating plants.

Provisions in the DSI PSCs allow BPA to restrict deliveries to the DSIs, in order to protect BPA firm loads, in the event of forced outages, unanticipated project delays, poor performance of existing plants, or system stability problems. Changing the type of DSI service changes the level of resources which BPA must plan to insure firm service to its firm customers.

If the methodology used for the 1982 rate filing were used today, the forced outage requirement for BPA would be 1289 MW in January of 1989 (line 36+37, page TA-227, 1988 Pacific Northwest Loads and Resources Technical Appendix). The DSI restriction rights provide all 1289 MW of forced outage reserve in the same time period (line 39, page TA-227, 1988 Pacific Northwest Loads and Resources Technical Appendix).

If 50 percent of the DSI load is served with nonfirm resources as the first quartile is now, the equivalent of one less quartile would be available for forced outage reserves. Assuming the fourth quartile remains unavailable for such reserves, the equivalent of one quartile remains available to provide forced outage reserves. As of January 1989, this is approximately 848 MW; forced outage reserves total 1289 MW (1988 Pacific Northwest Loads and Resources Technical Appendix, P. TA-227). Thus 441 MW additional forced outage reserves would need to be installed. The cost of the power would be offset to some degree by the savings from the deferral of resources previously planned to serve the additional interruptible load. An alternative stability scheme would also need to be put in place to replace the amount of stability reserves no longer provided by the DSI load. (Fourth quartile outage reserves are not included on a planning basis since that quartile can only be restricted for 15 minutes at a time.)

4.1.2.2. Resource Operations

4.1.2.2.1. Changes by Type of Resource

Appendix H-5 shows the projected changes in annual average generation by type of resource for all the alternatives for expected loads and gas price and for high Northwest loads. With the expected gas prices and loads, Case A shows lower levels of generation from nuclear plants than under the No Action Alternative after year 2000. This result is a consequence of the differences between the two alternatives in resource development described in the previous section. Case A shows about the same generation as under the No Action Alternative from coal-fired resources throughout the study period with the expected values for gas price and Northwest and Southwest load. After 1998, the change in combustion turbine generation is substantially less on a percentage basis under the No Action Alternative than under Case A. The No Action Alternative has additional coal resources that are less expensive to operate than combustion turbines.

SAM accounts for small resources and conservation by reducing the projected loads by the amount of these resources and dispatching the large generating plants and making purchases to meet this reduced load. Thus, the mode of operation of small resources is not altered by the model in response to circumstances.

With high Northwest loads, nuclear generation is the same with either the No Action Alternative or Case A. Nuclear generation is generally base-loaded in SAM because its variable cost is low. There are substantial differences in generation by coal-fired plants after 1999, with No Action having more coal generation. These results reflect the relative patterns of addition of new generating resources under the two alternatives discussed in the previous section. Combustion turbine generation is substantially less on a percentage change basis under the No Action Alternative than under Case A when high Northwest loads are assumed after 1998, primarily because more baseload thermal plants (coal) are added in the No Action Alternative. With the additional resources added in the No Action Alternative, there is a similar firm load/resource balance in both alternatives. Under Case A, however, combustion turbines are a proportionately larger part of the resource base. In addition, there is a larger nonfirm load, especially in the fall, which the model attempts to meet under Case A.

4.1.2.2.2. Hydro System Impacts

Anadromous and Resident Fish. Case A resulted in Columbia River flows that were typically higher August through November and lower the remainder of the year than with No Action. In low flow conditions, the average August through December flows increased between 1 and 4 kcfs at Priest Rapids, while January through July flows (excepting March, April, and May which showed no change) decreased 1 to 4 kcfs. In average and high water conditions, flows continued to increase in the fall, but spring and summer flows were unaffected. Very little change in flow was observed at Lower Granite. Water budget flows were met on the mid-Columbia in all conditions.

Flows at Vernita Bar were 0.60 percent more likely to exceed 125 kcfs at Priest Rapids during the October and November spawning period, and the number of occurrences of flows less than 70 kcfs at Vernita Bar in the spring increased 0.73 percent for this alternative. This alternative is not expected to affect fall chinook production in the Hanford Reach.

Overgeneration spill decreased an average of 8 percent April through August.

FISHPASS predicted a decline in relative system survival between 0.0 and 0.2 percent under this alternative for subyearling chinook, steelhead, and sockeye. Decreases in survival of yearling chinook and steelhead occurred primarily in the lower river. Subyearling chinook survival decreased throughout the entire river system. In no case did the relative decrease in survival for any of the species originating in any pool exceed one percent. This alternative would have little affect on anadromous fish.

A complete description of the criteria used for evaluating the impacts of hydro operations on anadromous fish may be found in Appendix H-1a. Comparison of data between this Alternative and the Base Case for overgeneration spill; relative system survival and frequency of relative survival changes exceeding 1 and 5 percent; monthly average flow at Lower Granite, Priest Rapids, and The Dalles; and frequency analysis of meeting the Vernita Bar requirements and Columbia River Water Budget; can be found in Appendices H-1d through H-1h.

Elevations at the four major storage reservoirs were lower September through May with little change in the summer months. Low runoff conditions (i.e., the lowest 10 percent of water years) produce the greatest change in reservoir elevations, particularly in the winter months. Reductions in reservoir elevations at Dworshak, Hungry Horse, and Libby averaged 0.44 feet, 0.83 feet, and 1.21 feet during the April through November period in low flow years. Grand Coulee showed little change. Elevation changes in high and average water conditions were less than 1 foot. The frequency of decreases in elevation from the Base Case greater than five feet, however, may be as high as 41 percent at Dworshak, 56 percent at Hungry Horse, and 61 percent at Libby during the fall growth period, so there is a potential for some negative fishery impacts.

The mean flows at Libby and Hungry Horse did not change appreciably under this alternative. Flows at Libby were generally between 0 and 2 kcfs higher September through December, and slightly less the remainder of the year (less than 0.5 kcfs). Flow changes at Columbia Falls were generally less than 0.5 kcfs. The frequency of flows less than 4.0 kcfs into the Kootenai River increased very slightly in spring and summer months. And flows were greater than 4.5 kcfs at Columbia Falls slightly more often during the spawning period, October through December. No impact is expected to resident fish in the Kootenai and Flathead rivers as a result of this case.

A complete description of the criteria used for evaluating the impacts of hydro operations on resident fish may be found in Appendix H-1a. Comparison of data between this Alternative and the Base Case for monthly average flow at Libby and Columbia Falls and frequency of flows being less than 4.0 kcfs at Libby, and greater than 4.5 kcfs and less than 3.5 kcfs at Columbia Falls; and end-of-period reservoir elevations and the frequency of change in reservoir elevation greater than 5 feet for Dworshak, Grand Coulee, Libby, and Hungry Horse and can be found in Appendices H-1i through H-1k.

Similar results were obtained for different assumptions with respect to growth of Northwest loads, growth of Southwest loads, and gas prices.

Recreation. Recreation analyses were performed for Grand Coulee, Dworshak, Libby, and Hungry Horse through the computation of recreation indices. The derivations of these indices are described in Appendix H-2. Larger values for the recreation indices indicate improved opportunities for recreation at the reservoirs. (Detail on changes in reservoir levels is included in the section on Anadromous and Resident Fish, above.) The recreation indices computed for the four reservoirs for all alternatives and their differences from the Base Case are shown for the median gas price and Northwest and Southwest load growth assumptions in Appendix H-2. Case A resulted in very small changes in the recreation indices for the four reservoirs. For example, the seasonal average recreation index changed relative to no action by less than 1 percent for Dworshak, Lake Roosevelt, and Libby, and changed by less than 3 percent for Hungry Horse under Case A.

Recreation impacts for Lake Pend Orielle are analyzed in terms of the probability of the elevation of that reservoir being at least 2,054 feet at the end of April, a level that enhances the annual Kokanee and Kamloops Fishing Derby, which occurs around May 1 each year. This probability is tabulated for selected years for all the alternatives in Appendix H-2. The probability is essentially unchanged for Case A relative to no action.

System Refill. Case A with expected Northwest and Southwest loads and gas prices resulted in a slight degradation in the probability of refill compared to the No Action Alternative in 14 of the 20 years of the analysis. (See Appendix H-4.) In the year with the greatest change, probability of refill went from 0.905 with No Action to 0.875 under Case A. Similar results were obtained for different assumptions with respect to growth of Northwest loads, growth of Southwest loads, and gas price. When low Northwest loads were assumed, however, probability of refill changed (by an insignificant amount) in only one year of the analysis.

Irrigation. Case A has no impact relative to no action on irrigation for the same reasons described for Alternative 1.2. (See Appendix H-3.) This was true for all assumptions of gas price and Northwest and Southwest load growth tested.

4.1.2.2.3. Thermal Plant Operations

Coal and Combustion Turbine Plant Generation Changes. Changes in the operation of existing coal and combustion turbine plants dedicated at least partially to supplying power to the region are shown in Appendices H-5 and H-6. Changes are shown on an annual basis in units of average annual MW. Operation of each of the existing coal plants is consistently higher with Case A in 1998, and beyond with the expected Northwest and Southwest loads and expected gas price. These increases are negligible on a percentage basis for Colstrip, Corette, Centralia, and Bridger, but are as high as about 22 percent for Valmy and 35 percent for Boardman in certain years. The large differences in generation between Case A and the No Action Alternative for Valmy and Boardman occur as a consequence of adding two nuclear plants in the No Action case, compared to one nuclear plant in Case A. Therefore, more surplus power is available in the No Action case to displace the high-cost Valmy and Boardman coal-fired plants; operation of these plants at these times is higher under Case A.

With expected loads and gas prices, nearly all the change in combustion turbine operation in Case A compared to the No Action case occurs at the Beaver plant. This plant is the region's only combined cycle combustion turbine; it is more efficient and has a lower operating cost than other combustion turbine facilities. Since fewer resources are acquired in Case A, existing resources are run more. Thus, the Beaver plant operates more in Case A. SAM dispatches Beaver to serve load prior to other combustion turbine facilities. The Beaver plant never operates at more than a 10 percent plant factor in any year under either the No Action Alternative or Case A with expected loads and gas price. Generation changes at other combustion turbine plants are sometimes large on a percentage basis, but plant factors for all these other plants are always low, about 3 percent or less. Changes in generation at these other plants are consequently always numerically small.

When high Northwest loads are assumed, trends similar to those using expected loads occur in the differences between Case A and No Action. However, the changes are generally not large on a percentage basis. In fact, for the last 8 years of the analysis, changes in generation at Colstrip, Corette, Centralia, and Bridger are zero or near zero. With higher loads, these plants tend to operate at or near capacity in either case in the latter years of the analysis.

Again, combustion turbine generation changes are dominated by changes in the operation of the Beaver facility. With high Northwest load growth, the Beaver facility is operated more in the 1989 to 1998 period either under the No Action Alternative or Case A than when expected loads and gas price are assumed. For example, the plant operates at a plant factor as high as 31 percent in 1996 in the No Action Alternative. With high Northwest loads, operation of the Beaver plant is higher under the No Action Alternative than under Case A over the 1989 through 1998 period, but generally by only small amounts. In 1997, Case A resulted in a decrease of about 26 percent in generation at Beaver relative to No Action; decreases of about 10 percent to 12 percent occurred in 2 years; decreases in other years were much smaller. Changes in generation at other combustion turbine plants were small 1989 through 1998. In the 1999 through 2008 period, generation by the Beaver plant is about 3 to 4 times higher under Case A than under the No Action Alternative. In this period, other combustion turbine plants also operated more under Case A, with large percentage differences but small numerical differences between their operation under Case A and No Action.

Air Quality. Air quality impacts would result from changes in the operation of coal and combustion turbine plants. More annual generation at these types of facilities means that annual average concentrations of air pollutants in the areas affected by the plants would be higher. There would not necessarily be an increase in the peak concentrations of air pollutants produced by the plants.

Using the methodology described in Appendix H-7, air quality impacts were determined for the individual coal plants affected. The air quality impacts for each plant for all the alternatives for expected gas prices and load and high Northwest loads are shown in Appendix H-7. The analysis found air quality impacts of Case A resulting from changes in operation of existing coal-fired plants to be negligible in all cases. Changes in all cases were small when compared with either ambient air quality standards or prevention of significant degradation criteria.

Negligible impacts on air quality are expected from Alternative 4.1, Case A with expected loads and gas prices relative to the No Action Alternative from differences in operation of combustion turbine facilities. This is because ambient levels of air pollutants from the Beaver facility, at which nearly all the difference in combustion turbine generation occurs, are low and the facilities operating levels remain fairly low (less than 10 percent plant factor) in both cases. Air quality impacts of the other combustion turbine facilities will continue to be negligible under either the No Action Alternative or Alternative 4.1, Case A since their operating levels are very low in both and they also seem to produce low ambient levels of air pollutants. (See Appendix H-7.)

With high Northwest loads, the Beaver facility would have larger impacts on air quality than if expected loads and gas prices occurred. However, ambient air pollution concentrations produced by the plant over the short term would still not be significant. The impact of Alterntative 4.1, Case A relative to the No Action Alternative would exhibit itself in a slight, probably negligible, decrease in average annual concentrations of air pollutants in the area impacted by the plant over the period 1989 through 1998, and a similar increase in annual average pollutant concentration over the period 1999 through 2008. Operation of other combustion turbine facilities was also increased by Alternative 4.1, Case A relative to the No Action Alternative in the period 1999 through 2008, but only by small amounts. Therefore, since these facilities also seem to only result in very small ambient levels of air pollution, only negligible effects on air quality from these facilities would also be expected from Alternative 4.1, Case A.

Fuel Use. More or less generation by coal-fired plants means more or less consumption of coal, a nonrenewable resource. Using the methodology described in Appendix H-8, changes in coal consumption were determined for coal-fired plants supplying power to the region. In the analysis, there is a linear relationship between coal consumption and generation for each plant. The coal consumption impacts for each plant for all the alternatives with assumptions of high Northwest loads and expected loads and gas prices are shown in Appendix H-8.

Over the 20 years of study, under Alternative 4.1, Case A, Beaver is projected (assuming combined cycle operation) to require about 25,800 million cubic feet, or 88 percent, more natural gas than under the No Action Alternative when expected loads and gas prices are assumed. When high Northwest loads are assumed, Beaver is projected to use about 27,600 million, or 28 percent, more cubic feet of natural gas than under the No Action Alternative over the 20 years of the study. To put these figures in perspective, Pacific Northwest natural gas consumption currently is about 270 billion cubic feet per year. Fuel use impacts at the other combustion turbines were very small since the changes in generation were very small and were not quantitatively determined.

Land Use. Changes in coal plant generation may affect land use, because changes in generation cause more or less coal to be mined during a period of time. All coal-fired generating plants supplying power to the region except Valmy rely on surface coal mines for their fuel supply. Thus, generation changes mean that more or less surface area is disturbed each year as a consequence of mining. It is likely, however, that the total surface area disturbed for coal mining will be unchanged: the amount of economically recoverable coal at a mining property does not change, and mining is likely to occur until all economically recoverable coal is mined.

Using the methodology described in Appendix H-8, changes in annual disturbance of land for coal mining were determined for the individual surface coal mines affected. The land disturbance impacts for each plant for all the alternatives with assumptions of expected loads and gas prices and of high Northwest loads are shown in Appendix H-8.

Water Use. Impacts on the supply of surface and ground water from changes in operation of the coal-fired generating plants were conservatively computed using the method used for the Final Intertie Development and Use Environmental Impact Statement and described in Appendix H-8. Tables 4.1.3 and 4.1.4 show the results. It should be noted that the water consumption analysis was based on the positive and negative differences in generation between Alternative 4.1, Case A and No Action of the largest magnitude throughout the 20 years of the SAM analysis. Therefore, the results shown in Tables 4.1.3 and 4.1.4 are only for two particular years, which are not necessarily uniform for the various plants. Differences in water use for all other years of the SAM analysis are of smaller magnitude than those shown on the Tables. Water use impacts for the Boardman and Colstrip plants tend generally to be very small on a percentage basis simply because they draw their water from relatively large rivers, the Columbia and the Yellowstone. Also, the minimum discharge upon which the percentages in the second to the last column of Table 4.1.3 are based is an artificial value for annual minimum stream flow computed by multiplying the minimum discharge given in the seventh column of the Table by the number of days in a year (i.e., 365). This makes the analysis very conservative.

The impacts on both ground and surface waters of Alternative 4.1, Case A relative to the No Action Alternative are small regardless of whether expected loads and gas prices are assumed, or whether high Northwest loads are assumed. The largest changes in water use by any plant relative to a very conservatively estimated minimum annual flow in the stream acting as the source of water were a little more than 1 percent of the computed minimum annual flow in the streams supplying water to the plants. For the Valmy plant, water consumption increased with Alternative 4.1, Case A relative to the No Action Alternative by an amount equivalent to 2.4 percent of the annual acquifer recharge in one year when high Northwest loads were assumed. (Water use impacts were not calculated for the Corette plant since the differences in generation between Alternative 1.2 and the No Action Alternative were very small.)

4.1.2.3. DSI Effects

Under the alternative, the aluminum industry would tend to suffer, since more of its power supply is at risk in both the operational and planning senses. When less load is served as firm, there is a greater possibility of a reduction in aluminum loads and net benefits. The electrolytic reduction process for aluminum smelting is sensitive to power interruptions.

Interruptions could cause operational difficulties, loss in process efficiency, and increased costs. Increased expenditures could come from production loss, potline restart, and extra labor and materials.

An increase in interruptibility from the present 25 percent to 50 percent would probably result in 50-200 MW lost aluminum load. Production efficiency could decline, and the economic viability of the Pacific Northwest industries could suffer.

The impact on the economic viability of the aluminum smelters could be lessened if their power rates were to decline based on increased load interruptibility.

4.1.3. Environmental Effects--Case B--100 Percent

4.1.3.1. Future Resource Development

With Case B, firm load obligations would decrease significantly. The increase in nonfirm load would place no resource obligation on the region. As a result, no new major generating resource additions are projected with the expected gas price and Northwest and Southwest load growth through the study period (through 2008). Under the No Action alternative, assuming the same gas price and load growth, two nuclear plants would be projected to be added, one in 2000 and one in 2004. Less conservation and development of small renewable resources occurs under Case B as well. In the No Action Alternative, with expected load growth and gas price, 781 aMW of conservation and 324 aMW of small renewables were projected to be developed during the study period, 1989 to 2008. In Case B, 651 aMW of conservation and 116 aMW of small renewables were projected over the same period under the same assumptions.

No additional combustion turbine facilities were developed.

In order to achieve load/resource balance, the model assumes short-term acquisitions of energy from other utility systems when a major resource cannot be brought on line in time to meet load, or when the resource deficit is small or short enough not to justify bringing on a major resource. With expected loads and gas price, no such acquisitions were needed under either the No Action Alternative or Case B.

Under the assumption of high Northwest load growth in Case B, additions of a nuclear plant would be needed in both 1997 and 1999 and one coal-fired generating plant per year from 2000 through 2008. With high Northwest load growth, No Action is projected to result in two nuclear plants coming on line in 1997, five typically sized coal-fired generating units added in 1999, and 11-12 additional typical coal plants added between 2000 and 2008. Nine hundred forty-nine aMW of conservation and 957 aMW of small renewables were projected to be developed over the study period, 1989 to 2008, under the No Action Alternative with high Northwest load growth. In Case B, 899 aMW of conservation and 752 aMW of small renewables were projected over the same period with high loads.

Assuming high load growth, no new combustion turbine facilities were added.

With high Northwest loads, short-term energy acquisitions from other utility systems are used to avoid deficits 1989 through 1998 in the No Action Alternative. In Case B, however, even with high Northwest load growth, short-term energy was needed only in 1996, the year before one of the nuclear plants was added. The amount of this acquisition was substantially less than that for any year with the No Action Alternative.

Appendix F discusses the generic impacts of conservation and of the development and operation of small resources, cogeneration, and nuclear and coal-fired generation.

If all DSI loads were served with nonfirm resources, the full 1289 MW (1988 Pacific Northwest Loads and Resources Technical Appendix, P. TA-227) of forced outage reserves would need to be replaced. An alternate stability scheme would also need to be put in place. The costs of acquiring the reserves would be offset by the savings from deferring the resources previously planned to meet the three quartiles of DSI load now served as firm, about 2545 MW in January 1989.

4.1.3.2. Resource Operations

4.1.3.2.1. Changes by Type of Resource

Appendix H-5 shows the projected changes in annual average generation by type of resource for all the alternatives for expected loads and gas price and for high Northwest loads. With the expected gas price and Northwest and Southwest loads, Case B shows significantly lower levels of generation from nuclear plants than with no action in the year 2000 and after. It also shows increases in coal-fired generation of about 40-60 aMW in 1998-1999 and 150-200 aMW in year 2000 and after. The changes in nuclear generation are a result of the differences in resource development between the two alternatives, as described in the previous section. Existing nuclear plants did not change their generation with Case B relative to the No Action Alternative. With no new nuclear generation added under Case B, operation of existing coal plants is increased to meet load growth in the post-1998 period. Combustion turbine generation is also generally lower with Case B relative to No Action through 2003, with substantial percentage differences in some years. After 2003, combustion turbine generation is higher with Case B than with the No Action Alternative, with roughly 50-70 percent increases in most years. However, with either no action or Case B, absolute levels of combustion turbine generation are low relative to the capability of these resources with the expected gas price and loads.

With high Northwest loads in Case B, coal fired generation is slightly higher prior to 1999 than under the No Action Alternative. Since the addition of resources, including conservation and small renewable resources, is delayed by the decrease in firm load, operation of existing coal-fired plants increases to provide power supply. Post-1999, coal-fired generation is much less under Case B than with No Action because additional coal plant capacity is being deferred.

With high Northwest loads in combination with Case B, combustion turbine generation is much less than under the No Action Alternative for all years through 1998, especially 1992 through 1998 when combustion turbine generation under No Action is high. Post-1998, combustion turbine usage in the No Action Alternative decreases as nuclear and coal plants are added. Combustion turbine generation after 1998 is higher in Case B by 20-50 percent.

4.1.3.2.2. Hydrosystem Impacts

Anadromous and Resident Fish

Note that uncertainty in the analysis of changes in hydro operations is heightened by recent proposals for listing salmon species as threatened or endangered under the Endangered Species Act, as well as by potential changes in hydro operations which may result from the System Operation Review. In reading this analysis, the reader should bear in mind that changes in or increased constraints on hydro operations resulting from these processes may reduce or eliminate the differences in operations between the No Action alternative and the other alternatives under consideration.

Case B could have potentially significant changes to the hydro system operation as a result of serving the entire DSI load (or an equivalent amount of firm load) with interruptible energy. Due to the shift of FELCC made surplus by decreased firm load, flows in the Columbia River during September through December were considerably higher, with reduced flows during the rest of the year. The pattern was similar for all water conditions. The maximum decrease in spring flow occurred in low water years. Water Budget flows were met on the mid-Columbia, although flows outside the Water Budget period, particularly June through August, were substantially reduced. The average flow reduction at Priest Rapids was 9 kcfs in June, 4 kcfs in July, and 6 kcfs in August in low water conditions. In a single year, monthly average flows may be reduced by as much as 15 kcfs at Priest Rapids. Fall flows remained high in average and high water conditions, but the reduction in spring and summer flows was much less (1 to 4 kcfs). Flows on the Snake River were reduced by 1 kcfs in the summer months of low runoff years.

Not only did fall flows exceed 125 kcfs more often at Vernita Bar in October and November (5.55 percent), but because of the reduced spring flows, there was a greater occurrence of flows less than 70 kcfs during the winter and spring months (3.1 percent).

Overgeneration spill decreased an average of 18 percent April through August as a result of serving the entire DSI load with nonfirm energy.

The relative change in system survival decreased for all stocks between 0.0 and 0.7 percent; the largest decrease occurred for subyearling chinook. Subyearling chinook survival decreased between 0.5 and 2.1 percent throughout the system, most particularly for fish originating in the Mid-Columbia stream reach. Survival of yearling chinook originating in the mid-Columbia improved slightly prior to the year 2005, but then decreased in all years for those fish entering below McNary Dam. The relative survival for yearling chinook entering below McNary decreased between 0.2 and 1.7 percent. Steelhead survival decreased between 0 and 1.1 percent, primarily in the lower river. Survival of sockeye stocks also declined. Potentially critical yearling and subyearling stocks affected include Methow River spring and summer chinook, Okanogan-Similkameen River summer chinook, Wells Hatchery summer chinook, and Tucannon River spring chinook. The system survival for these stocks is improving 20-30 percent over time as bypass systems are installed. Therefore, the changes caused by this alternative are not significant in view of the long-term survival improvements. Appendix H-1a provides an updated stock assessment for these affected stocks.

A complete description of the criteria used for evaluating the impacts of hydro operations on anadromous fish may be found in Appendix H-1a. Comparison of data between this Alternative and the Base Case for overgeneration spill; relative system survival and frequency of relative survival changes exceeding one and five percent; monthly average flow at Lower Granite, Priest Rapids, and The Dalles; and frequency analysis of meeting the Vernita Bar requirements and Columbia River water budget; can be found in Appendices H-1d through H-1h.

Elevations at the major Federal storage reservoirs were lower from September through May, particularly during the winter months. During the June through August period, reservoir elevations showed no change or a slight increase. This was true for all water conditions, with the greatest elevation changes occurring in low water years. The average decrease in reservoir elevation at Dworshak was 2.5 feet, at Hungry Horse 4.3 feet, and at Libby 5.0 feet from April through November in low water conditions (i.e., the lowest 10 percent of water years). The potential exists for the decrease in reservoir elevation to be as great as 10-12 feet during the fall growth period at each of the reservoirs except Grand Coulee. Reductions in reservoir elevations generally averaged less than 2 feet during the April through November period in average and high water years. Grand Coulee showed little change in elevation under any of the runoff conditions. The frequency of reservoir elevations decreasing in November by more than 5 feet from the Base Case under this alternative was as high as 77 percent at Dworshak, 68.5 percent at Hungry Horse, and 91 percent at Libby. Such reductions can be detrimental to fish growth and to fish such as Kokanee that spawn during the fall. The changes in reservoir elevations caused by this alternative could create serious impacts to resident fish populations.

Flows on the Kootenai River downstream of Libby were 1-3 kcfs higher in the fall, 2-5 kcfs lower in December, and lower, less than 1 kcfs, in the spring and summer. Flows on the Kootenai had a slightly greater frequency of being less than 4 kcfs, particularly in August. Flows occurring at Columbia Falls tended to be 1 to 3 kcfs higher in September and lower, less than 1 kcfs, the remainder of the year. There was little change in the frequency of flows less than 3.5 kcfs at Columbia Falls. However, flows during the kokanee spawning period (October 15 to December 15) were slightly more likely to be above 4.5 kcfs. It is not expected that these changes in river operations would cause significant impacts to the local resident fish populations.

A complete description of the criteria used for evaluating the impacts of hydro operations on resident fish may be found in Appendix H-1a. Comparison of data between this Alternative and the Base Case for monthly average flow at Libby and Columbia Falls and frequency of flows being less than 4.0 kcfs at Libby, and greater than 4.5 kcfs and less than 3.5 kcfs at Columbia Falls; and end-of-period reservoir elevations and the frequency of change in reservoir elevation greater than five feet for Dworshak, Grand Coulee, Libby, and Hungry Horse and can be found in Appendices H-1i through H-1k.

Similar results were obtained for different assumptions with respect to growth of Northwest loads, growth of Southwest loads, and gas prices.

Recreation. Recreation analyses were performed for Grand Coulee (Lake Roosevelt), Dworshak, Libby, and Hungry Horse through the computation of recreation indices. The derivations of these indices are described in Appendix H-2. Larger values for the recreation indices indicate improved opportunities for recreation at the reservoirs. The recreation indices computed for the four reservoirs for all alternatives and their differences from the Base Case are also shown in Appendix H-2 for expected gas price and Northwest and Southwest load growth. Case B resulted in small changes in the recreation indices from their values for the No Action Alternative for the four reservoirs. For example, the seasonal average recreation index changed by less than 1 percent relative to no action for Dworshak and Lake Roosevelt. The direction of the changes was not consistent over the years of the analysis. For Libby, changes were less than 2 percent and were most often adverse. For Hungry Horse, changes were less than 5 percent and were inconsistent in direction.

Recreation impacts for Lake Pend Orielle are analyzed in terms of the probability of the elevation of that reservoir being at least 2,054 feet at the end of April, a level that enhances the annual Kokanee and Kamloops Fishing Derby, which occurs around May 1 each year. This probability is tabulated for all the alternatives for selected years and shown in Appendix H-2. The probability is lower in most years with Case B relative to the No Action Alternative, by as much as about 7 percent.

System Refill. Case B, assuming expected Northwest and Southwest loads and gas price, resulted in a slight degradation in the probability of refill compared to no action in 16 of the 20 years of the analysis and a slight increase in one year. (See Appendix H-4.) In the year with the greatest change, probability of refill changed from 0.845 with the No Action Alternative to 0.800 under Case B. Similar results were obtained for different assumptions of growth of Northwest loads, growth of Southwest loads, and gas price. When low Northwest loads were assumed, however, probability of refill stayed the same or increased (by an insignificant amount) in all but 1 year of the analysis with Case B.

Irrigation. Case B has no impact relative to the No Action Alternative on irrigation for the same reasons described for Alternative 1.2. This was true for all assumptions of gas price and Northwest and Southwest load growth tested.

4.1.3.2.3. Thermal Plant Operations

Coal and Combustion Turbine Plant Generation Changes. Changes in the operation of coal and combustion turbine plants dedicated at least partially to supplying power to the region are shown in Appendices H-5 and H-6. Changes are shown in units of average annual megawatts. SAM projects large percentage decreases for Case B through about 1998 in the generation at Valmy and Boardman, the higher cost plants, assuming expected gas price and loads. The decrease relative to No Action occurs because firm loads are lower under Case B, and these higher cost plants are run less. The percentage changes in generation at the other coal-fired plants are not as significant, but the changes are generally increases after the year 2000. This is because in the No Action Alternative nuclear generation is run before coal-fired generation because of its lower variable costs. Thus, in the latter years of the analysis, coal-fired generation at all existing plants is generally lower for the No Action Alternative than with Case B.

With expected loads and gas price, nearly all the change in combustion turbine operation again occurs at the Beaver plant. However, the Beaver plant never operates at more than a 10 percent plant factor in any year under either the No Action Alternative or Case B with expected loads and gas price. Therefore, numerical changes between the No Action Alternative and Case B are fairly small. Changes on a percentage basis are often fairly large, with the generation levels at Beaver under Case B lower than under the No Action Alternative except for the last four years of the analysis. In the period 2004 through 2008, generation levels at Beaver are higher for Case B. Generation changes at other combustion turbine plants are sometimes large on a percentage basis, but plant factors for all these other plants are always very low, about 4 percent or less. Changes in generation at these other plants are consequently always numerically small.

When high Northwest loads are assumed, coal generation at existing plants is ramped up quickly, with increases in generation generally occurring in successive years once the surplus is gone in both the No Action Alternative and Case B. The less costly plants to operate are ramped up fastest. The model shows percentage differences in generation for particular coal-fired plants for certain years, particularly early in the study period, which are sometimes substantial. These changes are due to differences in the amount of resources (for example, conservation and small resources) added under the two alternatives, the plants' relative variable costs, and the operating levels of the individual plants in the No Action Alternative.

Combustion turbine generation changes again are dominated by changes in the operation of the Beaver facility. With high Northwest load growth, the Beaver facility is operated more (by factors of 4 to 10) in the 1992 to 1998 period under the No Action Alternative than under Case B. In the 1999 through 2008 period, the differences in the Beaver plant's operation are less substantial with Case B levels (higher by factors of about 1.2 to 1.5) than for the No Action Alternative. Changes in generation between the No Action Alternative and Case B at other combustion turbine plants were small 1989 through 2008. Until 1998, combustion turbines other than Beaver were generally operated slightly more in the No Action Alternative; from 1999 through 2008, they were operated slightly less relative to Case B, assuming high Northwest loads.

Table 4.1.3

ALTERNATIVE 4.1, CASE A: MAXIMUM IMPACT ON SURFACE WATERS OF THE PACIFIC NORTHWEST

STATE	PLANT	WATER BODY	MEAN ANNUAL DISCHARGE (AC-FT)	YEARS OF RECORD	RECENT YEAR DISCHARGE (AC-FT)	MINIMUM DISCHARGE (AC-FT/DAY)	YEAR	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN GENERATION (aMW)	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN WATER USE (AC-FT)	PERCENTS OF MINIMUM DISCHARGE 1/	RECORD RATING
EXPECTED LOADS AND GAS PRICE											
OR	Boardman	Columbia River	140100000	104 yrs	165700000	24000	1968	36.4	888	0.010	Excellent
								-20.3	-495	-0.0057	
WA	Centralia	Skookumchuck River	183300	1930–82	238600	167	1982	29.7	642	1.1	Good
								-19.0	-410	-0.67	
WY	Bridger	Green River	1277000	33 yrs	1677000	337	1955	29.3	633	0.51	Good-Poor
								-68.6	-1480	-1.2	
MT	Colstrip	Yellowstone River	8620000	1978–84	8780000	12246	1984	16.4	354	0.0079	—
								2/	2/	2/	
HIGH NORTHWEST LOADS											
OR	Boardman	Columbia River	140100000	104 yrs	165700000	24000	1968	29.0	708	0.0081	Excellent
								-2.6	-63.4	-0.0007	
WA	Centralia	Skookumchuck River	183300	1930–82	238600	167	1982	22.6	488	0.80	Good
								-17.4	-376	-0.62	
WY	Bridger	Green River	1277000	33 yrs	1677000	337	1955	21.8	471	0.38	Good-Poor
								-11.6	-251	-0.20	
MT	Colstrip	Yellowstone River	8620000	1978–84	8780000	12246	1984	2.2	47.5	0.0011	—
								-1.6	-34.6	0.0008	

1/ Percent of Minimum Discharge computed assuming minimum discharge occurs over the course of an entire year. This method tends to overstate the actual expected impacts.

2/ No decreases or zero changes occurred.

Table 4.1.4

ALTERNATIVE 4.1, CASE A: MAXIMUM IMPACT ON GROUNDWATER IN THE PACIFIC NORTHWEST

STATE	PLANT	WELL LOCATION	AQUIFER RECHARGE OR YIELD (AC-FT/YR)	LARGEST POSITIVE AND NEGATIVE CHANGES IN GENERATION (aMW)	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN WATER USE (AC-FT)	PERCENT OF RECHARGE OR YIELD
EXPECTED LOADS AND GAS PRICE						
NV	Valmy	Valmy aquifer near Valmy	9000	3.5	50.2	0.56
				-1.1	-15.8	-0.18
HIGH NORTHWEST LOADS						
NV	Valmy	Valmy aquifer near Valmy	9000	14.9	214	2.4
				-7.1	-102	-1.1

Air Quality. Air quality impacts result from changes in operation of coal plants and combustion turbines. Less annual generation at these types of facilities means that annual average concentrations of air pollutants in the areas affected by the plants would be lower. There would not necessarily be a reduction in the peak concentrations of air pollutants resulting from the plants.

Using the methodology described in Appendix H-7, air quality impacts were determined for the individual coal plants affected. The air quality impacts for each plant for all the alternatives for both expected loads and gas price and high Northwest loads are shown in Appendix H-7. The analysis found air quality impacts of Case B resulting from changes in coal-fired plant operation to be negligible in all cases. Changes in all cases were small when compared to either ambient air quality standards or prevention of significant deterioration criteria.

Negligible impacts on air quality are also expected from Alternative 4.1, Case B with expected loads and gas prices relative to the No Action Alternative from differences in operation of combustion turbine facilities. This is because ambient levels of air pollutants from the Beaver facility, at which nearly all the difference in combustion turbine generation occurs, are low and the facilities operating levels remain fairly low (less than 10 percent plant factor) in both cases. The No Action Alternative has an adverse impact when compared with Alternative 4.1, Case B over the period 1989 through 2003 on air quality impacts from combustion turbines. Air quality impacts of the other combustion turbine facilities will continue to be negligible under either the No Action Alternative or Alternative 4.1, Case B since their operating levels are very low in both and they also seem to produce low ambient levels of air pollutants. (See Appendix H-7.)

With high Northwest loads, the Beaver facility would have larger impacts on air quality than if expected loads and gas prices occurred. However, despite some rather large differences in degree to which the plant is used between the two Alternatives, ambient air pollution concentrations produced by the plant over the short term would still not be significant since the plant produces only very low ambient concentrations of pollutants. The impact of Alterntative 4.1, Case B relative to the No Action Alternative would exhibit itself in a small decrease in average annual concentrations of air pollutants in the area impacted by the plant over the period 1989 through 1998, and an increase of lesser magnitude in annual average pollutant concentration over the period 1999 through 2008. Operation of other combustion turbine facilities was also increased by Alternative 4.1, Case B relative to the No Action Alternative in the period 1999 through 2000, but only by small amounts. Therefore, since these facilities also seem to only result in very small ambient levels of air pollution, only negligible effects on air quality from these facilities would also be expected from Alternative 4.1, Case B.

Fuel Use. More or less generation by coal-fired plants means more or less consumption of coal, a nonrenewable resource. Using the methodology described in Appendix H-8, changes in coal consumption were determined for coal-fired plants supplying power to the region. The coal consumption impacts for each plant for all the alternatives for both expected loads and gas price and high Northwest loads are shown in Appendix H-8. Coal consumption impacts of Case B for each plant are in direct proportion to their differences in annual average generation found under the two alternatives.

Over the 20 years of study, under Alternative 4.1, Case B, Beaver is projected (assuming combined cycle operation) to require about 6,380 million cubic feet (about 22 percent) less natural gas than under the No Action Alternative when expected loads and gas prices are assumed. When high Northwest loads are assumed, Beaver is projected to use about 50,700 million (about 51 percent) less cubic feet of natural gas than under the No Action Alternative over the 20 years of the study. For comparison, Northwest natural gas use currently is about 270 billion cubic feet per year. Fuel use impacts at the other combustion turbines were very small since the changes in generation were very small and were not quantitatively determined.

Land Use. Changes in coal plant generation can affect land use, because changes in generation cause more or less coal to be mined during a period of time. All coal-fired generating plants supplying power to the region, except Valmy, rely on surface coal mines for their fuel supply. Thus, generation changes mean that more or less surface area is disturbed each year as a consequence of mining. It is likely, however, that the total surface area disturbed for coal mining will be unchanged: the amount of economically recoverable coal at a mining property does not change, and mining is likely to occur until all economically recoverable coal is mined.

Using the methodology described in Appendix H-8, changes in annual disturbance of land for coal mining were determined for the individual surface coal mines affected. The land disturbance impacts for each plant for all the alternatives and sensitivities are shown in Appendix H-8. Land disturbance impacts of Case B are also linearly related to the difference in annual average generation between the two alternatives.

Water Use. Tables 4.1.5 and 4.1.6 show the impacts on the supply of surface and ground water from differences in operation of the coal-fired generating plants. The impacts on both ground and surface waters of Alternative 4.1, Case B relative to the No Action Alternative are fairly small regardless of whether expected loads and gas prices are assumed, or whether high Northwest loads are assumed. The largest changes in water use by any plant relative to a very conservatively computed minimum annual flow in the stream acting as the source of water were a 1.6 percent increase in water consumption, and a 2.7 percent decrease (with high Northwest loads), both for Centralia. For the Valmy plant, water consumption increased with Alternative 4.1, Case B relative to the No Action Alternative by an amount equivalent to 5.5 percent of the annual acquifer recharge in one year when high Northwest loads were assumed.

Table 4.1.5

ALTERNATIVE 4.1, CASE B: MAXIMUM IMPACT ON SURFACE WATERS OF THE PACIFIC NORTHWEST

STATE	PLANT	WATER BODY	MEAN ANNUAL DISCHARGE (AC-FT)	YEARS OF RECORD	RECENT YEAR DISCHARGE (AC-FT)	MINIMUM DISCHARGE (AC-FT/DAY)	YEAR	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN GENERATION (aMW)	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN WATER USE (AC-FT)	PERCENTS OF MINIMUM DISCHARGE 1/	RECORD RATING
EXPECTED LOADS AND GAS PRICE											
OR	Boardman	Columbia River	140100000	104 yrs	165700000	24000	1968	36.9	900	0.010	Excellent
								-36.9	-900	-0.010	
WA	Centralia	Skookumchuck River	183300	1930-82	238600	167	1982	45.5	983	1.6	Good
								-21.8	-471	-0.77	
WY	Bridger	Green River	1277000	33 yrs	1677000	337	1955	49.4	1070	0.87	Good-Poor
								-72.1	-1560	-1.3	
MT	Colstrip	Yellowstone River	8620000	1978-84	8780000	12246	1984	29.4	635	0.014	—
								2/	2/	2/	
HIGH NORTHWEST LOADS											
OR	Boardman	Columbia River	140100000	104 yrs	165700000	24000	1968	76.4	1860	0.021	Excellent
								-17.7	432	-0.0049	
WA	Centralia	Skookumchuck River	183300	1930-82	238600	167	1982	41.2	890	1.5	Good
								-77.2	-1670	-2.7	
WY	Bridger	Green River	1277000	33 yrs	1677000	337	1955	70.3	1520	1.2	Good-Poor
								-30.6	-661	-0.54	
MT	Colstrip	Yellowstone River	8620000	1978-84	8780000	12246	1984	15.4	333	0.0075	--
								0.0	0.0	0.0	

1/ Percent of Minimum Discharge computed assuming minimum discharge occurs over the course of an entire year. This method tends to overstate the actual expected impacts.

2/ No decreases or zero changes occurred

Table 4.1.6

ALTERNATIVE 4.1, CASE B: MAXIMUM IMPACT ON GROUNDWATER IN THE PACIFIC NORTHWEST

STATE	PLANT	WELL LOCATION	AQUIFER RECHARGE OR YIELD (AC-FT/YR)	LARGEST POSITIVE AND NEGATIVE CHANGES IN GENERATION (aMW)	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN WATER USE (AC-FT)	PERCENT OF RECHARGE OR YIELD
EXPECTED LOADS AND GAS PRICE						
NV	Valmy	Valmy aquifer near Valmy	9000	28.3	406	4.5
				-16.4	-235	-2.6
HIGH NORTHWEST LOADS						
NV	Valmy	Valmy aquifer near Valmy	9000	34.3	492	5.5
				-7.1	-102	-1.1

4.1.3.3. DSI Effects

A 100 percent interruptibility scenario would probably result in over 200 MW of aluminum load losses. Operating difficulties and additional production costs could result, which could cause lower operating levels and possible plant closures.

4.2. No BPA Purchase Required to Exercise First Quartile Interruption Rights

4.2.1. Method of Analysis

The impacts of this alternative on DSI operations and on hydro system operations are not reasonably quantifiable. The following key factors are too speculative to predict: (1) the likelihood of need to purchase energy under the Base Case to comply with the contract terms described above or the likelihood of having to restrict DSI load when BPA has a purchase obligation for energy at reasonable cost; (2) the costs and sources of reasonable-cost energy; and (3) the degree of success BPA would have with requests for curtailment of nonessential electrical loads.

The analysis includes the effect of the alternative on DSI decisions to request FELCC shift (see Appendix C for review of FELCC shift and other borrowing techniques); the availability of replacement energy at costs low enough for the DSIs to purchase it and avoid curtailments; and BPA's practices for power planning and operations.

4.2.2. Environmental Effects

4.2.2.1. Effects on BPA and DSI Power Purchases

Under the existing PSC, BPA acquires any necessary energy up to "Reasonable Cost" before restricting the DSI first quartile during periods into which BPA has shifted FELCC, typically the months of September through December. If BPA does restrict DSIs, BPA assists DSIs in obtaining replacement energy supplies under the provisions of a separate agreement, known as the Industrial Replacement Energy (IRE) Agreement. BPA acts as purchasing agent for IRE, the full cost of which is paid for by DSI customers.

The alternative would tend to increase electric energy costs for DSIs since, during a period of insufficient power supply necessitating a restriction, the market for economy energy available for IRE would generally be priced at a rate greater than the effective BPA industrial rate. (Under the alternative, it is assumed that BPA would not restrict DSIs when BPA can purchase additional energy to serve them at a rate equal to or less than the effective industrial rate.)

BPA would save power purchase costs, but could lose revenue from future DSI load. If a DSI were to cut load in response to the restriction notice, it could take some time for the load to be brought back on-line. In fact, if the price of aluminum were low enough, the DSI might choose not to bring the load back on at all until prices recovered. In that case, BPA could lose revenue for many months.

This alternative would lessen the value of shifted FELCC to the DSI, thereby decreasing DSI quality of service by an unquantifiable amount. The customer would have less protection from a potential restriction and could risk paying either increased replacement energy costs to maintain its load or the cost of restoring operation after a period of restriction. (See Alternative 3.5 for a description of the effects of risk on the economic viability of DSIs and other customers.) A DSI might react to this alternative by reducing the amount of FELCC shift to which it subscribes. However, since this would further increase the risk of restriction, a DSI probably would pursue that action only if it was concerned about the take-or-pay requirement connected to FELCC shift (see section 8(b)(5) of the PSC).

Under this alternative, BPA could elect not to exercise its recall rights under other PSCs because of the increased ease of restricting the DSI First Quartile. As a result, the customers from whom BPA could recall power to serve this load might perceive BPA as being a better business partner, improving BPA's competitive posture.

Under the alternative, BPA could exercise its first quartile restriction right more promptly, because there would be no need to attempt to acquire or recall energy to serve the first quartile load before imposing the restriction. BPA's costs could decrease by an unquantifiable amount.

These effects on power purchase costs indicate some likelihood of an adverse effect on DSI productivity.

4.2.2.2. Resource Operations

Under this alternative, BPA would be more likely to exercise its first quartile restriction rights during the period into which BPA shifts FELCC to serve the first quartile, September through December. The market for economy energy tends to be higher in September through October due to high Pacific Southwest loads, so IRE would tend to be relatively expensive compared to other months of the year.

Under the No Action Alternative, BPA must endeavor to purchase or recall energy it would have purchased or recalled to serve other firm loads prior to restricting the first quartile of the DSI load when it is served by shifted FELCC. Under Alternative 4.2., BPA would choose whether to purchase, recall, or restrict DSIs. The economics of BPA's choice likely would take into account the possibility of a longer-lasting loss of DSI load as described above. It is expected that the Federal power system would be operated to its fullest extent in either case to produce energy. Although, under Alternative 4.2, BPA would not be directly responsible for certain costs of power required to maintain service to the DSI first quartile, operations are not expected to change. BPA would continue to operate its system in general to avoid probability of use of higher cost resources even if there was a possibility that some costs might have to be paid by another party.

If BPA chose to restrict and the DSIs chose to maintain load, the DSIs would purchase from other utilities to cover the first quartile. If BPA chose not to restrict, BPA would purchase or recall energy to cover the first quartile. Since the same quantity of energy acquisition would take place in either case, as long as DSIs did not choose to curtail loads instead, the same amount of energy would be produced, likely from the same Northwest and Southwest resources. Therefore, no change in operation of the regional power system is expected to occur. If DSIs chose not to purchase to cover the entire first quartile, but reduced operations, then the highest-priced resources in the Northwest and Southwest (non-Federal resources) would not be operated for that purpose.

4.3. Increase Quality of Service to First Quartile

4.3.1. Method of Analysis

The SAM and the Least Cost Mix Model were used to assess impacts on operation, need for resources, and planning reserves. Impacts related to operational reserves are analyzed qualitatively. Fish and wildlife impacts were assessed by the method described for Alternative 1.2.

System Analysis Model Assumptions. For the Base Case/No Action Alternative, the DSI first quartile load is served with nonfirm energy and other techniques, while the other quartiles are treated as firm load. For Alternative 4.3, the entire DSI load is considered firm for both planning and operational purposes. Specific amounts of load for each year of the study are shown in Appendix G-1. Second and third quartile restriction rights are assumed not to exist. The Least Cost Mix Model determined new resource additions.

4.3.2. Environmental Effects

Environmental implications arise due to the following changes:

First, the increase in firm load for which BPA must acquire resources;

Second, the potential change in hydro operations, i.e., reduced use of shifting techniques in September through December, due to serving the first quartile as firm load; and

Third, the need for replacement of reserves no longer provided by DSI restriction rights.

4.3.2.1. Future Resource Development

Alternative 4.3 increases the amount of firm load for which BPA must plan and acquire resources by the amount of DSI first quartile load. Therefore, under expected loads and high loads, resources are added slightly earlier or in slightly larger amounts under this alternative when compared to the Base Case. With the expected Northwest and Southwest loads and expected gas price, the addition of the first nuclear plant is brought on in 1999 rather than in 2000 as in the No Action Alternative. Addition of a second nuclear generating plant is also moved up, from 2004 under the No Action Alternative to 2003 with Alternative 4.3. Coal-fired generating units are not required through the end of the study period, 2008. No new combustion turbine resources were added. More conservation and small resources (which SAM treats as reductions in load rather than as dispatchable resources) are added with Alternative 4.3 than under No Action. The incremental amounts of these conservation and small resources are shown in Table 4.3.1.

Short-term acquisitions of energy from other utility systems were used to meet firm loads in 1990 (41 aMW), 1995 (6 aMW), and 1996 (97 aMW) with Alternative 4.3. No such acquisitions were required under the No Action Alternative.

With high Northwest loads assumed, two nuclear plants are added in about 1997 under either Alternative 4.3 or the No Action Alternative. Under No Action, about four coal-fired units are added to meet firm load in about 1998, and an additional coal-fired unit is added per year through the end of the study period. Under Alternative 4.3, one more coal-fired unit than under No Action is added in about 1998. New combustion turbine resources were not required with Alternative 4.3 with high Northwest loads. There was no difference in the amounts or timing of additions of conservation or small resources between Alternative 4.3 and the No Action Alternative when high Northwest loads are assumed.

With high Northwest loads, Alternative 4.3 requires more short-term acquisitions of energy from other utility systems than the No Action Alternative. Over the period 1989 through 1998, additional yearly acquisitions range from 805 to 885 aMW.

Generic environmental impacts of nuclear, coal, and conservation resources are discussed generically in Appendix F.

Since BPA would forgo all rights to restrict DSI load in Alternative 4.3, BPA would have to secure additional forced outage and stability reserves. The DSIs provide these reserves through BPA's contract right (§7(b)) to interrupt their entire load for prescribed periods of time. (See Alternative 4.4, "Background on Reserves" for greater detail.) The SAM does not analyze short-term phenomena such as DSI interruptions for forced outage or stability reasons. The amount of forced outage and stability reserves provided by the DSIs is 1289 MW for January 1989 (1988 Pacific Northwest Loads and Resources Technical Appendix, P. TA-227). If §7(b) interruption rights did not exist, 1289 MW of reserve resources would be lost. BPA's ratemaking studies of the value of the DSI forced outage and stability reserves have assumed that combustion turbine resources would replace the DSI reserves if they were unavailable. Environmental impacts of combustion turbines are described in Appendix F.

TABLE 4.3.1

INCREASES IN AMOUNTS OF CONSERVATION AND SMALL RESOURCES (DIFFERENCES BETWEEN ALTERNATIVE 4.3 AND NO ACTION) EXPECTED LOADS AND GAS PRICE

YEAR	CONSERVATION aMW	SMALL RESOURCES aMW	TOTAL aMW
1989	2	0	2
1990	2	0	2
1991	2	317	319
1992	8	317	325
1993	20	378	398
1994	33	391	424
1995	86	404	490
1996	57	334	391
1997	66	333	399
1998	75	209	284
1999	84	209	293
2000	93	209	302
2001	100	209	309
2002	109	209	318
2003	117	209	326
2004	122	209	331
2005	124	240	364
2006	123	240	363
2007	121	240	361
2008	118	240	358

4.3.2.2. Resource Operations

4.3.2.2.1. Changes in Total Generation

If the first quartile were considered to be firm load instead of interruptible, the region would be obligated to acquire resources to meet it. The Least Cost Mix Model projects a portion of these additional resources to be conservation and small resources, which reduce loads in SAM. Thus, these resources are not included in the total generation tables in Appendix H-5. Since with Alternative 4.3 more conservation and small resources are used than under the No Action Alternative, less generation is shown in Appendix H-5.

With high Northwest loads, this decrease in generation does not occur. Under this scenario, Alternative 4.3 and the No Action Alternative acquire identical amounts of conservation and renewable resources. Also, since in Alternative 4.3 all load is considered to be firm, there are fewer curtailments (or restrictions). (NOTE: The fact that there are any restrictions at all is due to the fact that SAM models some probability of failure to serve firm load.) As a result, more load is served under Alternative 4.3.

4.3.2.2.2. Generation Changes by Type of Resource

Appendix H-5 shows the projected changes in annual average generation by type of resource for all the alternatives for the expected load and gas price conditions. It also shows all other sensitivities analyzed. When expected loads and gas price are assumed, Alternative 4.3 generally showed relatively small changes from No Action in generation by each resource type. In most years, each resource type generated less under Alternative 4.3 than under No Action. Differences in nuclear generation did not occur except in years where there were differences between the alternatives in the timing of adding new nuclear generation.

Differences in combustion turbine generation between the No Action Alternative and Alternative 4.3 were not consistent in direction or magnitude. A few years showed large percentage changes (as large as a 41 percent decrease), but all numerical changes were small in the context of total generation capability.

With high Northwest loads, coal and nuclear generation differences between Alternative 4.3 and No Action largely correspond to the differences in the timing and quantity of additions of these types of resources. Combustion turbine generation under the No Action Alternative is much higher 1989 through 1998 with high Northwest loads than with expected loads. Alternative 4.3 with high Northwest loads resulted in combustion turbine generation not substantially different from No Action during this period. Post 1998, combustion turbine generation with high Northwest loads is less under either Alternative 4.3 or No Action; the differences between the two alternatives were inconsistent in direction and relatively small (under 20 percent at most and generally much less).

4.3.2.2.3. Hydrosystem Impacts

Anadromous and Resident Fish. The effect on the hydrosystem of serving the entire DSI load as 100 percent firm is a slight shift in flow out of the fall months into other months in low and average water conditions. In low flow years, monthly flows in the Columbia River decrease an average of 1-4 kcfs August through April 15, and increase 1-2 kcfs April 16 through July. During average flow conditions, monthly flows decrease an average of 3 kcfs September and October, and increase an average of 1 to 3 kcfs December through March. Spring and summer flows are unaffected in average water conditions.

In high flow years, flows at The Dalles and Priest Rapids tend to increase during October through December by about 4 kcfs and decrease 1 or 2 kcfs in September, February, and May. No change in flow was observed at Lower Granite. In all cases water budget flows were maintained on the mid-Columbia.

Flows at Vernita Bar were 3.0 percent more likely to exceed 125 kcfs at Priest Rapids in October and November and 1.6 percent more likely to remain above 70 kcfs throughout the spring.

Overgeneration spill increased as the entire DSI load is assumed to be served entirely with firm energy, leaving additional unmarketable nonfirm energy available. Overgeneration spill increased 24 percent April through August.

Relative system survival increased very slightly for all species; increases were generally less than one half of one percent. This alternative would have little effect on anadromous fish.

A complete description of the criteria used for evaluating the impacts of hydro operations on anadromous fish may be found in Appendix H-1a. Comparison of data between this alternative and the Base Case can be found in Appendices H-1d through H-1h for: overgeneration spill; relative system survival and frequency of relative survival changes exceeding one and five percent; monthly average flow at Lower Granite, Priest Rapids, and The Dalles; and frequency analysis of meeting the Vernita Bar requirements and Columbia River water budget.

Reservoir elevations were considerably higher with this alternative, especially in low runoff years. In low water years, Dworshak's average April through November elevation increased 7.0 feet, Hungry Horse's average elevation increased 12.2 feet, and Libby's elevation increased 4.8 feet. There was little change in the spring and summer elevations in average and high runoff conditions, although fall and winter flows averaged 1 to 5 feet higher. Little change was observed in the elevation of Grand Coulee. The frequency of reservoir elevations being greater than 5 feet from the Base Case between September and November ranged from 8 to 26 percent at Dworshak, 19 to 35 percent at Hungry Horse, and 3.5 to 18 percent at Libby. The frequency that elevations would be less than 5 feet from the Base Case in the fall was 0 at Dworshak, 0 to 1.5 percent at Hungry Horse, and 0 to 21 percent at Libby. This scenario could benefit resident fish residing in the major Federal storage reservoirs.

Changes in flow downstream of Libby and Hungry Horse dams were generally less than one kcfs. There was no change in the frequency of flows being less than 3.5 kcfs at Columbia Falls and a slight improvement in maintaining flows above 4 kcfs at Libby. Therefore, impacts to resident fish residing in the Kootenai and Flathead rivers are not expected.

A complete description of the criteria used for evaluating the impacts of hydro operations on resident fish may be found in Appendix H-1a. Comparison of data between this alternative and the Base Case for monthly average flow at Libby and Columbia Falls and frequency of flows being less than 4.0 kcfs at Libby, and greater than 4.5 kcfs and less than 3.5 kcfs at Columbia Falls; and end-of-period reservoir elevations and the frequency of change in reservoir elevation greater than five feet for Dworshak, Grand Coulee, Libby, and Hungry Horse can be found in Appendices H-1i through H-1k.

Similar results were obtained for different assumptions with respect to growth of Northwest loads, growth of Southwest loads, and gas prices.

Recreation. Recreation effects are related to changed reservoir levels. Details on the changes in reservoir levels was provided under Anadromous and Resident Fish above. Recreation analysis was performed for Grand Coulee, Dworshak, Libby, and Hungry Horse through the computation of previously described recreation indices. The derivations of these indices are described in Appendix H-2. The recreation indices computed for the four reservoirs for all alternatives and their differences from the Base Case are shown in Appendix H-2 for the expected gas price and Northwest and Southwest load growth assumptions. Alternative 4.3 resulted in very small changes in the recreation indices for the four reservoirs. For example, under Alternative 4.3 relative to the No Action alternative, the seasonal average recreation index increased by less than 2 percent for Dworshak and by less than 1 percent for Lake Roosevelt and Libby, and increased by less than 7 percent for Hungry Horse.

Recreation impacts for Lake Pend Oreille are analyzed in terms of the probability of the elevation of that reservoir being at least 2,054 feet at the end of April. That level enhances the annual Kokanee and Kamloops Fishing Derby, which occurs around May 1 each year. This probability is tabulated in Appendix H-2 for selected years--1991, 1993, 1995, 1997, 2001, and 2005--for all the alternatives analyzed with SAM. The probability is slightly enhanced in five of the six years, and degraded by about 6 percent in 1997 by Alternative 4.3 relative to the No Action Alternative.

System Refill. Assuming expected loads and gas prices, Alternative 4.3 improved the probability of system refill in all but 1 year of the analysis. In that one year, the probability of refill was the same under both alternatives. The amount of improvement with Alternative 4.3 relative to No Action varied from year-to-year. The greatest improvement was in 1999, when SAM projected the probability of July refill to be 0.810 with No Action and 0.855 with Alternative 4.3.

Assuming high Northwest loads, the probability of July refill is generally slightly higher in the early years of the analysis with No Action. Starting in 1998, however, SAM projects probabilities of system refill to be generally higher with Alternative 4.3. The largest change in probability of refill is in 2002, when with No Action it was 0.845 and with Alternative 4.3 was 0.890.

Irrigation. The text describing impacts of Alternative 1.2 also describes the method for analyzing irrigation impacts. Alternative 4.3 did not change the likelihood of Lake Roosevelt's elevation being at or above 1240 feet relative to the No Action Alternative.

4.3.2.2.4. Thermal Plant Operations

Changes in Existing Coal and Combustion Turbine Plant Operations. Changes in the amount of operation of individual coal plants dedicated at least partially to supplying power to the region are shown in Appendix H-6 on an annual basis in units of average annual megawatts. SAM results generally show reductions in operation of each existing coal-fired plant for Alternative 4.3 relative to the No Action Alternative from 1991 on with the expected values for loads and gas price. This is because acquisition of conservation and consumer-applied renewable resources decreases load and reduces the need for power generation. The largest decreases on a percentage basis occur at Valmy and Boardman, the more expensive plants to run. When high Northwest loads are assumed, there are negligible changes in operation of individual coal plants through 1998. After 1998, generation at Valmy and Boardman is generally decreased by 10 to 30 percent, in favor of additional coal-fired capacity that is expected to have lower variable operating and fuel costs than these two plants.

With expected loads and gas price, combustion turbine generation levels and the size of changes in generation which occur between the No Action Alternative and Alternative 4.3 are again predominantly due to the Beaver plant. Generation at that plant is higher in all years 1989 through 1998 (except for one) with Alternative 4.3 rather than with No Action, assuming expected loads and gas prices, but these increases relative to No Action were small in terms of aMW, the largest increase being 2.6 aMW. In the period past 1998, changes in Beaver generation with Alternative 4.3 relative to No Action were less regular, being increases in some years and decreases in others. The magnitude of these changes are typically somewhat larger than in 1989 through 1998, but under either Alternative 4.3 or No Action, the Beaver facility is not projected to exceed a plant factor of 5 percent. Changes in generation between the No Action Alternative and Alternative 4.3 at the other combustion turbine facilities included in SAM are projected to be very small numerically with expected loads and gas prices.

When high Northwest load growth is assumed, generation from Beaver is higher in all years in the period 1989 through 1998, typically by about 5 to 10 percent. Beaver operates much more when high loads are assumed than with expected loads and gas prices with plant factors as high as 32 percent. After 1998, generation at Beaver drops off drastically with the highest plant factor being about 6 percent under either Alternative. The generation levels are still higher in all but 1 year under Alternative 4.3, but the differences are not large, the highest for any year being 6.4 aMW.

Air Quality. Air quality impacts result from changes in operation of coal plants and combustion turbines. Less annual generation at these types of facilities means that annual average concentrations of air pollutants in the areas impacted by the plants would be lower; there would not be necessarily a reduction in the peak concentrations of air pollutants resulting from the plants.

Air quality impacts were determined for the individual coal plants affected using the methodology described in Appendix H-7. Appendix H-7 shows the air quality impacts for each plant for all the alternatives analyzed with SAM for both expected loads and gas price and high Northwest loads. The analysis showed air quality impacts of Alternative 4.3 resulting from changes in operation of existing coal-fired plants to be negligible in all cases.

With expected loads and gas prices, under Alternative 4.3, the Beaver facility is expected to have small adverse effects on air quality in 1989 through 1998, relative to the No Action Alternative, corresponding to the general increases in generation for the facility described above. These changes are projected to be small since the changes in generation are small and the ambient air pollutant concentrations from the plant are also small. After 1998, the changes in generation at Beaver become inconsistent from year to year, so the air quality impacts of Alternative 4.3 relative to the No Action Alternative will be beneficial in some years and adverse in others. However, they will continue to be small since the plant factor remains low in both alternatives and the plant produces only small ambient levels of pollutants. The other combustion turbine facilities included in SAM exhibited very small changes in generation between the No Action Alternative and Alternative 4.3, such that one can conclude air quality impacts of the Alternative 4.3 from these facilities would be negligible.

When high Pacific Northwest loads are assumed, Beaver will generally have more adverse effect on air quality under Alternative 4.3 than under the No Action Alternative throughout the study period. However, even though the generation changes are much larger for Beaver in the 1989 through 1998 period than when expected loads and gas price are assumed, the impacts are not expected to be significant because Beaver only produces low ambient concentrations of air pollutants. The impact would likely be most noticeble in some small increase in annual average air quality data. Again, even with high Pacific Northwest loads, the other combustion turbines operate at very low levels and are likely to have negligible impacts on air quality.

Fuel Use. More or less generation by coal-fired plants corresponds to more or less consumption of coal, a nonrenewable resource. Using the methodology described in Appendix H-8, changes in coal consumption were determined for existing coal-fired plants supplying power to the region. The coal consumption impacts for each plant for all the alternatives for both expected loads and gas price and high Northwest loads are tabulated in Appendix H-8. In most years, Alternative 4.3 resulted in savings of coal relative to the No Action Alternative when expected values for load and gas price are assumed. These savings are substantial (10 to 30 percent) in some years for the higher cost plants, Boardman and Valmy. With high Northwest loads, there are only small changes in coal consumption for all plants through 1998. After that period, coal use at Boardman and Valmy was generally reduced, tracking the changes in generation at the existing plants described above.

Over the 20 years of study, under Alternative 4.3, Beaver is projected (assuming combined cycle operation) to require about 2,300 million cubic feet (about 8 percent) more natural gas than under the No Action Alternative when expected loads and gas prices are assumed. When high Northwest loads are assumed, Beaver is projected to use about 9,360 million (about 9 percent) more cubic feet of natural gas than under the No Action Alternative over the 20 years of the study. For comparison, current Northwest natural gas consumption is about 270 billion cubic feet per year. Fuel use impacts at the other combustion turbines were very small since the changes in generation were very small and were not quantitatively determined.

Land Use. Land use is affected by changes in coal plant generation because changes in generation accelerate or decelerate mining of coal. All coal-fired generating plants supplying power to the region except Valmy rely on surface coal mines for their fuel supply. Thus, generation changes mean that more or less surface area is disturbed as a consequence of mining each year. It is likely that the total surface area disturbed for coal mining will be unchanged, however, because the amount of economically recoverable coal at a mining property is unchanged. Mining is likely to occur until all economically recoverable coal is mined.

Using the methodology described in Appendix H-8, changes in annual disturbance of land for coal mining were determined for the individual surface coal mines affected. The land disturbance impacts for each plant for all the alternatives for expected loads and gas prices and for high Northwest loads are tabulated in Appendix H-8. Land disturbance impacts of Alternative 4.3 resulting from changes in coal-fired plant operation parallel the changes in generation and coal consumption described above except for the Valmy plant. Land use was not affected by changes in Valmy's operation because its source of coal is underground.

Water Use. Tables 4.3.2 and 4.3.3 show the impacts on the supply of surface and ground water from differences in operation of the coal-fired generating plants. The differences on both ground and surface waters of Alternative 4.3 relative to the No Action Alternative are small regardless of whether expected loads and gas prices are assumed, or whether high Northwest loads are assumed. The largest changes in water use by any plant relative to a very conservatively computed minumum annual flow in the stream acting as the source of water were a 1.2 percent increase in water consumption, and a 2.1 percent decrease, both with expected loads and gas price and both for Centralia. For the Valmy plant, the largest water consumption difference was a decrease with

Alternative 4.3 relative to the No Action Alternative by an amount equivalent to 2.6 percent of the annual acquifer recharge. Coincidentally, this occurred both with expected loads and gas prices, and with high Northwest loads.

4.3.2.3. DSI Effects

This option assumes that the DSI load is 100 percent rather than 75 percent firm. An increase in power rates might accompany such an increase in the quality of service. However, rate design changes are not examined in this EIS: the complexity of ratemaking issues exceeds the broad policy scope of this analysis.

With its power supply 100 percent firm for operational and planning purposes, the aluminum industry's economic viability is better in this scenario than in

Table 4.3.2

ALTERNATIVE 4.3: MAXIMUM IMPACT ON SURFACE WATERS OF THE PACIFIC NORTHWEST

STATE	PLANT	WATER BODY	MEAN ANNUAL DISCHARGE (AC-FT)	YEARS OF RECORD	RECENT YEAR DISCHARGE (AC-FT)	MINIMUM DISCHARGE (AC-FT/DAY)	YEAR	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN GENERATION (aMW)	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN WATER USE (AC-FT)	PERCENTS OF MINIMUM DISCHARGE 1/	RECORD RATING
EXPECTED LOADS AND GAS PRICE											
OR	Boardman	Columbia River	140100000	104 yrs	165700000	24000	1968	2.2	53.7	0.0006	Excellent
								-36.1	-881	-0.010	
WA	Centralia	Skookumchuck River	183300	1930-82	238600	167	1982	33.9	732	1.2	Good
								-60.1	-1300	-2.1	
WY	Bridger	Green River	1277000	33 yrs	1677000	337	1955	2.8	60.5	0.049	Good-Poor
								-80.9	-1750	-1.4	
MT	Colstrip	Yellowstone River	8620000	1978-84	8780000	12246	1984	2/	2/	2/	--
								-26.6	-575	-0.013	
HIGH NORTHWEST LOADS											
OR	Boardman	Columbia River	140100000	104 yrs	165700000	24000	1968	4.8	117	0.0013	Excellent
								-37.5	-915	-0.010	
WA	Centralia	Skookumchuck River	183300	1930-82	238600	167	1982	17.9	387	0.63	Good
								-8.3	-179	-0.29	
WY	Bridger	Green River	1277000	33 yrs	1677000	337	1955	1.1	23.8	0.019	Good-Poor
								-8.2	-177	-0.14	
MT	Colstrip	Yellowstone River	8620000	1978-84	8780000	12246	1984	0.9	19.4	0.0004	--
								-2.3	-49.7	-0.0011	

1/ Percent of Minimum Discharge computed assuming minimum discharge occurs over the course of an entire year. This method tends to overstate the actual expected impacts.

2/ No increases of zero changes occurred.

Table 4.3.3

ALTERNATIVE 4.3: MAXIMUM IMPACT ON GROUNDWATER IN THE PACIFIC NORTHWEST

STATE	PLANT	WELL LOCATION	AQUIFER RECHARGE OR YIELD (AC-FT/YR)	LARGEST POSITIVE AND NEGATIVE CHANGES IN GENERATION (aMW)	LARGEST POSITIVE AND NEGATIVE ANNUAL CHANGES IN WATER USE (AC-FT)	PERCENT OF RECHARGE OR YIELD
EXPECTED LOADS AND GAS PRICE						
NV	Valmy	Valmy aquifier near Valmy	9000	3.1 -16.5	44.5 -237	0.49 -2.6
HIGH NORTHWEST LOADS						
NV	Valmy	Valmy aquifier near Valmy	9000	3.6 -16.4	51.7 -235	0.57 -2.6

the Base Case. Even with an assumed increase in the wholesale power rate, aluminum loads increase due to better quality of service, increasing the industry's net benefits. The net benefits of non-DSI customers decline with this alternative relative to No Action. The power rates of other BPA customers would increase due to resource acquisitions to serve the DSI first quartile as firm load. Their net loss is not made up by the aluminum industry gains. Thus, in general, the region is projected to be less well off under this alternative.

4.4. No DSI-Type Reserves

4.4.1. Method of Analysis

Qualitative determination was made of the options available to BPA to replace forced outage and stability reserves and second quartile planning reserves with other reserves.

The effects of loss of energy reserves from second quartile restriction rights were analyzed using SAM. The restriction of the DSI second quartile in the event of a Federal resource delay or poor performance is governed by terms of the DSI PSC (see section 7(d) of the Generic DSI Power Sales Contract in Appendix M and summary in Appendix B). Second quartile restrictions are not automatically made whenever a Federal resource is delayed or does not perform up to expectations. Second quartile restrictions are permitted by the DSI PSCs only when resource delays or poor performance result in or make worse a firm energy deficit, and when all other means to serve the second quartile by acquiring or recalling energy at "Reasonable Cost" are exhausted. Thus, before restricting the second quartile the model serves it with nonfirm energy and purchases from other utilities when possible.

Under Alternative 4.4, second quartile restriction rights are no longer available in the event of plant delay. While SAM assumes some variability in the arrival of new resources, any occurrence of plant delay is identical in Alternative 4.4 and the No Action Alternative.

4.4.2. Environmental Effects

Environmental implications of Alternative 4.4 arise from the need to acquire replacement resources for reserves assumed not to be provided through DSI restriction rights. As described in Chapter 2, provisions in the existing DSI PSCs allow BPA to restrict deliveries to the DSIs in order to protect BPA firm loads in the event of forced outages, unanticipated project delays, poor performance of existing plants, loss of the AC Intertie during heavy import conditions, and system stability problems.

4.4.2.1. Background on Reserves

For most utilities, reserves are provided by maintaining idle generation in excess of the utility's firm requirements. This backup generation is generally used infrequently but provides insurance against unexpected demands or conditions on the utility's system. Reserves for the Federal system are provided in part by BPA's contractual rights to restrict the DSI load under the conditions described in the DSI contracts. Having these restriction rights allows BPA to receive revenues from the sale of energy and capacity that otherwise would remain idle in order to provide system reserves.

BPA adjusts the DSI rates to take into account the system reserves provided by the contractual right to restrict the DSI load. BPA's ratemaking analysis for determining the value of DSI reserves remained constant from the 1982 rate filing through the 1985 filing. Consequently, the level of the value of the DSIs' reserves remained fairly constant in nominal terms. In the 1987 rate filing BPA adopted the IP-PF Rate Link, which incorporates by means of a predetermined formula the results of the 1985 value of reserves analysis in the DSIs' rates in effect on or before June 1990. One of the reasons BPA was able to predetermine the formula is that the value of reserves analysis was expected to continue to produce stable results absent significant changes in DSI loads or resource acquisitions. (The IP-PF Rate Link was considered in the DSI Options Study EIS. See Final Environmental Impact Statement, Direct Service Industry Options, April 1986, p. 114 - 115, 122. BPA has proposed extending the IP/PF link to September 30, 1995.)

4.4.2.2. Future Resource Development

4.4.2.2.1. Replacement for Forced Outage Reserves

Forced outage reserves are additional sources of capacity available to meet system emergencies due to an unscheduled outage of generating capacity. Forced outage reserves maintain the operating integrity of the Federal system. On a planning basis, the amount of reserve margin necessary to protect the operating integrity of the Federal system in a given year is based on the projection of operating resources in that year. Required reserve margins are estimated following the guidelines in the Pacific Northwest Coordination Agreement. The estimated margins for reserves are based on 5 percent of the total capacity of hydro, small thermal, combustion turbines, cogeneration, renewable and miscellaneous resources, and 15 percent of large thermal capacity. (See 1988 Pacific Northwest Loads and Resources Technical Appendix, p. 13.) Any action that increases the amount of operating resources would increase the Federal system's forced outage reserve requirement. BPA currently projects that the highest amount of forced outage reserves required for the Federal system in Operating Year 1988-1989 is 1,303 MW in November of 1988. The same amount is projected for Operating Year 1993-1994. (See 1988 Pacific Northwest Loads and Resources Technical Appendix, Federal System Table 2, line 36 + 37, page TA-227.)

The amount of system reserves that can be provided by the DSI restriction rights in any given year is contingent on the amount of DSI load served during that year. On a long-term basis, BPA plans on only two-thirds of the industrial firm load (the DSIs' second and third quartiles) being available to meet BPA's reserve requirement.

The DSIs' first and fourth quartiles are not included in the amount of expected reserves provided by DSI restrictions. BPA does not plan on forced outage reserves from the first quartile because it is not a firm load for planning purposes. Fourth quartile forced outage reserves are not included on a planning basis because BPA can restrict that quartile for only 15 minutes at any one time, according to the PSC.

Any action that changes the amount of DSI firm load served by BPA will change the amount of forced outage reserves BPA plans to have available. Under the assumptions used for developing the 1988 long-term projections of loads and resources, BPA expects that DSI restriction rights for forced outages will be sufficient to meet BPA's forced outage reserve obligations through the duration of the current PSCs. (1988 Pacific Northwest Loads and Resources, Technical Appendix, Federal Table 2, p. T233.)

Absent the right to restrict the DSI load for forced outages, BPA would have to acquire the reserves from other sources. BPA could attempt to find other load in the region which would be willing to be interrupted in the event of a forced outage. No assessment has been made of the amount of non-DSI regional load that would be willing to be interrupted for reserve purposes. It is unlikely that the amount of non-DSI load willing to provide system reserves through interruption would be comparable to the amount or size of interruptible load provided by DSI restriction rights. In addition, reserves provided by restricting non-DSI load would present other difficulties, the most important of which is coordination. The DSIs' loads are significantly larger than the individual loads of retail consumers. Therefore, a larger number of retail customers would have to curtail power in order to achieve the same level of reserves as the DSIs provide. Further, because feeder lines likely would serve both customers willing to be interrupted and customers unwilling to be interrupted, load curtailment might have to be implemented by the individual consumer. The logistics of BPA contacting a large number of consumers to curtail their loads, especially in emergency, could be impractical.

If the current forced outage reserves were not available, BPA most likely would acquire resources of similar operating characteristics or purchase power to replace them. It is possible that the output of combustion turbines would be used for that purpose, as was assumed in BPA's ratemaking studies valuing DSI reserves, described in 4.4.2.1 above.

The environmental impacts of combustion turbines are described in Appendix F.

4.4.2.2.2. Replacement for Stability Reserves

Under current contracts, all of the DSI load can be restricted for up to 15 minutes and up to a cumulative megawatthour total specified in the PSC. These restriction rights were accounted for in the valuation of stability reserves in the DSI value of reserves calculation for BPA ratemaking. If stability reserves are not available, an alternative stability scheme would need to be put in place.

In its 1982 through 1985 ratemaking value of reserves analyses, BPA valued DSI stability reserves on the basis of the cost of load tripping equipment that could be used as an alternative to the DSI restriction rights. The amount of stability reserves provided by DSIs was estimated to be approximately 3000 MW. The cost of the load tripping equipment necessary to isolate various portions of the BPA system was estimated in 1983 to be approximately $800,000.

Other options would be to reduce the reliability of the system or reduce imports on the Pacific Northwest-Southwest Intertie. The reduction in reliability could result in the uncontrolled loss of load for some contingencies, which is unacceptable by current standards. The amount of any Intertie import reduction would vary greatly depending on operating conditions, and thus would be impossible to reasonably estimate.

4.4.2.2.3. Replacement for Second Quartile Planning Reserves

As described in Chapter 2, second quartile restriction rights can be implemented when a planned-for Federal resource, including conservation, is delayed or performs poorly. It is expected that BPA would not acquire resources to provide replacement for second quartile reserves, but would increase the generation at existing resources, make short-term purchases from other entities who would increase operation of their existing resources, or plan to build resources ahead of need. Short-term purchases would bridge the time until a delayed BPA resource came on-line or poor performance was mitigated by advancing another resource to serve firm load. See the section below for changes in resource operations.

4.4.2.3. Resource Operations

4.4.2.3.1. Changes by Type of Resource

If significant changes were observed, they would involve increased operations at those higher-priced coal and combustion turbine plants which are not normally heavily used.

The only time there would be any difference in resource operations between Alternative 4.4 and the No Action Alternative for a given set of assumptions on load growth and gas price would be when the second quartile is restricted by the SAM. In the No Action Alternative with expected Northwest and Southwest load growth, the second quartile was never actually restricted. Thus, there is no projected difference in the impacts relative to resource operations of Alternative 4.4 and the No Action Alternative.

When high Northwest load growth was assumed, the model projected restrictions of the DSI second quartile in eight games out of 200 during 1996, and in one game during 1997. The results showed very small changes (on the basis of results averaged over 200 games) between the No Action Alternative and Alternative 4.4 in three (1996, 1997, and 1998) out of the 20 years of the study in generation by hydroelectric resources, coal-fired plants, and combustion turbines, and similar small changes in purchases. There would typically be some use of shaping and flexibility to provide service to the second quartile for as long as possible prior to its restriction, which would result in some change in resource operation. Total generation changed by about 100 aMW when second quartile restrictions actually occurred.

4.4.2.3.2. Hydrosystem Impacts

Anadromous and Resident Fish. The comparison of this alternative with the No Action Alternative shows no substantive changes to any of the factors analyzed to determine fishery impacts. Similar results were obtained for different assumptions with respect to growth of Northwest loads, growth of Southwest loads, and gas prices.

A complete description of the criteria used for evaluating the impacts of hydro operations on anadromous fish may be found in Appendix H-1a. Comparison of data between this alternative and the Base Case for overgeneration spill; relative system survival and frequency of relative survival changes exceeding one and five percent; monthly average flow at Lower Granite, Priest Rapids, and The Dalles; and frequency analysis of meeting the Vernita Bar requirements and Columbia River water budget; can be found in Appendices H-1d through H-1h.

A complete description of the criteria used for evaluating the impacts of hydro operations on resident fish may be found in Appendix H-1a. Comparison of data between this alternative and the Base Case for monthly average flow at Libby and Columbia Falls and frequency of flows being less than 4.0 kcfs at Libby, and greater than 4.5 kcfs and less than 3.5 kcfs at Columbia Falls; and end-of-period reservoir elevations and the frequency of change in reservoir elevation greater than five feet for Dworshak, Grand Coulee, Libby, and Hungry Horse and can be found in Appendices H-1i through H-1k.

System Refill, Irrigation, and Recreation. The model results projected no substantive differences between Alternative 4.4 and the No Action Alternative in hydro generation under any of the sets of assumptions tested. Therefore, there is no substantive difference in impacts on system refill, irrigation, or recreation.

4.4.2.3.3. Thermal Plant Operations

Coal and Combustion Turbine Plant Generation Changes. Generation changes in coal plants indicated by SAM results for Alternative 4.4 assuming high Northwest loads occur primarily at the Boardman and Valmy plants. These are higher-cost coal plants and would therefore be less likely to be used under normal circumstances.

There were no significant changes in combustion turbine operation between the No Action Alternative and Alternative 4.4 with high Northwest loads. Under the No Action Alternative, Beaver and more expensive turbines are operated to forestall restriction of the second quartile. Thus there is not the disparity of results for Beaver versus other combustion turbine plants seen for other alternatives. However, all these differences in annual generation for combustion turbine plants are very small, typically 0.0 to 0.3 aMW. Differences occur from 1996 through 1998. Of all the combustion turbine facilities, however, only the Beaver facility is operated with a plant factor of over 10 percent under either Alternative 4.4 or the No Action Alternative.

Air Quality. Air quality impacts for the changes in coal-fired generation were computed using the methodology described in Appendix H-7. Air quality impacts computed on this basis were negligible for Alternative 4.4. No difference in combustion turbine generation is projected by SAM for Alternative 4.4 relative to the No Action Alternative with expected loads and resources, so there is also no difference projected in the air quality impacts of operating combustion turbines.

Since the differences in generation for individual, existing combustion turbine generation facilities projected by SAM between Alternative 4.4 and the No Action Alternative were very small when high Northwest loads were assumed, and the ambient levels of air pollutants attributable to these types of facilities seem typically very low (See Appendix H-7), the air quality impacts of Alternative 4.4 relative to No Action would be negligible in this situation.

Fuel Use. More or less generation by coal-fired plants means more or less consumption of coal, a nonrenewable resource. Using the methodology described in Appendix H-8, changes in coal consumption were determined for coal-fired plants supplying power to the region. The coal consumption impacts for each plant for all the alternatives for both expected loads and gas price and high Northwest loads are tabulated in Appendix H-8. The analysis found coal consumption impacts of Alternative 4.4 to be negligible in all cases.

Since differences in generation by gas turbine generating facilities between the No Action Alternative and Alternative 4.4 were also very small, it can be concluded that the impacts on gas and oil consumption of Alternative 4.4 are expected to be very small.

Over the 20 years of study, under Alternative 4.4, no increase in fuel usage at the Beaver facility is projected relative to the No Action Alternative with expected loads and gas prices. When high Northwest loads are assumed, Beaver (assuming combined cycle operation) is projected to use about 2,130 million (about 2 percent) less cubic feet of natural gas than under the No Action Alternative over the 20 years of the study.

Land Use. Using the methodology described in Appendix H-8, changes in annual disturbance of land for coal mining were determined for the individual surface coal mines affected. The land disturbance impacts for each plant for all the alternatives and sensitivities are tabulated in Appendix G. The analysis found land disturbance impacts of Alternative 4.4 resulting from changes in coal-fired plant operation to be negligible in all cases, for the same reasons cited for air quality and fuel consumption impacts.

Water Use. Alternative 4.4 would have only negligible effects on water consumption by coal-fired generating plants. The SAM results reported only very minor differences in generation for Alternative 4.4 relative to the No Action Alternative, and then only for the Valmy (for 1998) and Boardman (for 1997 and 1998) plants with the assumption of high Northwest loads. Because the differences changes in generation were so limited, the methodology applied to compute water consumption changes (see Appendix H-8) was not applied for this Alternative.

4.4.2.4. DSI Effects

Overall effects on DSIs would be similar to those described qualitatively for Alternative 4.3. As for Alternative 4.3, DSI rates would be expected to increase without the credit for value of reserves. No effects are expected from the assumption that the second quartile is served as firm load, with no restriction for delay in Federally planned resources, since not many new Federal resources are planned in the time period involved.

CATEGORY 5. FIRM INDUSTRIAL LOAD OBLIGATION ON BPA

5.1. Larger DSI Load

5.1.1. Method of Analysis

Alternatives 5.1 and 5.2 are analyzed by determining extreme high and low levels of DSI contract demands, given current levels and certain assumptions regarding Technological Improvement Allowances and assignment of contract demand. The resulting levels of contract demand represent, in effect, the possible upper and lower limits of BPA's obligations under the present DSI PSCs (within certain constraints described below) and are shown in Table 5.1.1. These extremes are not reasonably achievable without radical changes in the contracts and, therefore, should be viewed as analytical endpoints to bracket the results of more reasonable, moderate potential changes.

5.1.2. Environmental Effects

Environmental implications arise due to changes in the need for resource acquisition and due to changes in operations of the industrial plants. This alternative shows the effects of growth of DSI contract demand. To reach this high level, the total allowable Technological Allowance increases under existing contracts are added to the total of 1988 contract demands, and all existing contract demands are assumed to be used, possibly by assignees under a liberal BPA policy on DSI contract assignment.

TABLE 5.1.1
MORE/LESS DSI FIRM LOAD
July 25, 1989

ALTERNATIVE 5.1: MORE DSI FIRM — ALTERNATIVE 5.2: LESS DSI FIRM

	LARGER ALUMINUM LOADS 1988 CONTRACT DEMAND WITH FULL TECHNOLOGICAL INCREASES							SMALLER ALUMINUM LOADS			
ALUMINUM	1990	1992	1994	1996	1998	2000	2001	1988 Contract Demand	Full Potent Conmod	Cont-Dem W-75%-CM (Base)	Cont-Dem W-100%-CM (Max Reduce)
Alcoa	370.1	380.2	390.3	400.4	410.5	420.6	425.7	360.0	8.4	353.7	351.6
Columbia Aluminum	303.7	311.3	318.9	326.5	334.1	341.7	345.5	296.1	1.3	295.1	294.8
Columbia Falls	441.7	455.9	470.1	484.3	398.5	512.7	519.8	427.5	26.5	407.6	401.0
Intalco	480.2	492.3	504.5	516.6	528.8	540.9	547.0	468.0	28.2	446.9	439.8
Kaiser	759.2	780.9	802.6	824.3	846.0	867.7	878.6	737.5	78.0	679.0	659.5
Northwest Aluminum	175.9	177.8	179.7	181.6	183.5	185.4	186.3	174.0	13.7	163.7	160.3
Reynolds	724.8	749.0	773.1	797.2	821.4	845.5	857.7	700.7	44.0	667.7	656.7
Vanalco	243.0	251.0	259.0	267.0	275.0	283.0	287.0	235.0	26.0	215.5	209.0
Aluminum Total	3498.6	3598.4	3698.2	3797.9	3897.8	3997.5	4047.6	3398.8	226.1	3229.2	3172.7
Change from 1988 Contract Demand	99.8	199.6	299.4	399.1	499.0	598.7	648.8			-169.6	-226.1
Percent Change	2.9%	5.9%	8.8%	11.7%	14.7%	17.6%	19.1%			-5.0%	-6.7%

	LARGER NON-ALUMINUM LOADS 1988 CONTRACT DEMAND WITH FULL TECHNOLOGICAL INCREASES							SMALLER NON-ALUMINUM LOADS			
NON-ALUMINUM	1990	1992	1994	1996	1998	2000	2001	1988 Contract Demand	Full Potent Conmod	Cont-Dem W-75%-CM (Base)	Cont-Dem W-100%-CM (Max Reduce)
ACPC	5.2	5.3	5.5	5.7	5.9	6.0	6.1	5.0		5.0	5.0
Carborundum	34.5	34.9	35.4	35.8	36.3	36.7	36.9	34.0	34.0	0.0	0.9
Georgia Pacific	35.2	36.4	37.5	38.7	39.9	41.1	41.7	34.4		34.4	34.4
Gilmore	31.0	32.0	32.9	33.9	34.9	35.9	36.4	30.0	30.0	0.0	0.0
Oremet	18.6	19.2	19.8	20.4	21.0	21.5	21.8	18.0		18.0	18.0
Pacific Carb.	9.6	9.8	10.1	10.4	10.6	10.9	11.2	9.3	9.3	0.0	0.0
Penwalt	86.8	89.6	92.4	95.2	98.0	100.8	102.2	84.0		84.0	84.0
Port Townsend	16.7	16.8	16.9	17.0	17.2	17.3	17.3	16.6		16.6	16.6
Hanna	123.3	126.7	130.0	133.3	136.7	140.0	141.7	120.0		120.0	120.0
Non-Aluminum Total	360.9	370.7	380.5	390.4	400.5	410.2	415.3	351.3	73.3	278.0	278.0
Change from 1988 Contract Demand	9.6	19.4	29.2	39.1	49.2	58.9	64.0			-73.3	-73.3
Percent Change	2.7%	5.5%	8.3%	11.1%	14.0%	16.8%	18.2%			-20.9%	-20.9%

	LARGER TOTAL DSI LOADS 1988 CONTRACT DEMAND WITH FULL TECHNOLOGICAL INCREASES							SMALLER TOTAL DSI LOADS			
	1990	1992	1994	1996	1998	2000	2001	1988 Contract Demand	Potent Load Conmod	Cont-Dem W-75%-CM (Base)	Cont-Dem W-100%-CM (Max Reduce)
DSI TOTAL	3859.5	3969.1	4078.7	4188.3	4293.3	4407.7	4462.9	3750.1	299.4	3507.2	3450.7
Change from 1988 Contract Demand	109.4	219.0	328.6	438.2	548.2	657.2	712.8			-242.9	-299.4
Percent Change	2.9%	5.8%	8.8%	11.7%	14.6%	17.5%	19.0%			-6.5%	-8.0%

The alternative assumes that increases in contract demands for Technological Allowances may be permitted for reasons other than for additional environmental protection equipment and energy efficiency improvements, for equipment such as plant expansion, for example.

The available Technological Allowance Pool is 1 percent of the 1981-82 Contract Demand, plus 1 percent of the 1978-81 Contract Demands minus the Technological Allowances already granted. In the years 1981-88, 237 MW of the Technological Allowance was not used by the DSIs. For the years 1989-2001, the allowable Technological Allowance will be 476 MW. If the DSIs were allowed and took all the unused past and future Technological Allowance to 2001, it would total approximately 237 MW (past) plus 476 MW (future), for 712.8 MW total Technological Allowance, as shown in Table 5.

Since the 1988 DSI Contract Demand is 3750.1 MW, an increase of 712.8 MW would result in a total Contract Demand by 2001 of 4462.9 MW, or a 19 percent increase. The 712.8 MW increase by year 2001 represents the maximum contractually allowable increase in Contract Demand due to technological allowance and transfers of contract demand. The 4462.9 MW represents the high extreme of possible DSI load, as constrained by the Northwest Power Act. Total maximum DSI load for selected years under this alternative is shown in Table 5.1.1.

Increased DSI operations and productivity can have physical and socioeconomic effects. These have been described in prior environmental documents: Draft Role EIS (1977), Appendix C, pp. IV-143-190; Final Role EIS (1980), pp. IV-93-96, Northwest Alloys FEIS (August 1977) and the DSI Options FEIS (1986).

5.2. Smaller DSI Firm Load

5.2.1. Method of Analysis

The method of analysis is the same as that described under Alternative 5.1 above.

5.2.2. Environmental Effects

This alternative analyzes the effects of constraining DSI load so that a reasonable lower limit to the DSI Contract Demand is achieved. To determine this level, it was assumed that the full conservation/modernization load reduction of 226 MW was realized and subtracted from the 1988 aluminum contract demand. (For the No Action alternative, only 75 percent of the 226 MW conservation/modernization load reduction was assumed to be realized.) For the nonaluminum DSIs, the Carborundum, Gilmore, and Pacific Carbide contracts are assumed to be terminated (i.e., no transfers to new owners or activation by present owners). For all DSIs, no Technological Allowances are assumed. The 1988 DSI Contract Demand of 3750 MW would be reduced to 3507 MW, a 7 percent decrease. Some "wheel turning" load may be affected, but since the results would be small (about 3 percent of total DSI loads) and it is not specifically addressed in the contracts, it will not be considered in this EIS analysis. Table 5.1 also shows the effects of Alternative 5.2 on the individual and total Contract Demands of the DSIs.

5.3. NLSLs - Remove Constraints

5.3.1. Method of Analysis

The analysis for Alternatives 5.3 and 5.4 studies extreme high and low scenarios which are not realistic, but which serve as endpoints to bracket the effects of more reasonable, moderate potential changes. The analysis concerns that portion of the region's non-DSI industrial sector which is served by preference customer utilities. It primarily seeks to assess the effect on growth of that load sector due to changes in applicable BPA rates to the serving utilities. Industrial customers of IOUs would not be affected because there is no difference in the BPA firm requirements power rates for new large industrial loads versus other loads of IOUs. The analysis compares the alternative, which is a high case, to the No Action Alternative under existing contracts.

The alternative case reflects a modification of the NLSL provisions of section 3(13) of the Northwest Power Act and section 8 of the utility PSC. The alternative case assumes that the average rate charged all NLSLs in preference customer service areas is the sum of the PF rate and a retail markup. This necessarily involves some inaccuracy in assumed retail rates since utilities have some flexibility to establish special rates for industrial consumers. For the No Action Alternative, it is assumed that the rate charged all NLSLs in preference customer service areas under the existing contracts is the sum of the New Resource rate and the same retail markup as in the high case.

5.3.1.1. Estimated Industrial Loads for Alternative Case

The analysis uses the Joint BPA-Council Medium Case forecast for public utility industrial loads to derive load growth by Standard Industrial Code (SIC) between 1988 and 2008.

NLSL growth could occur without net industrial load growth if, for instance, a large industrial plant (greater than 10 MW) shut down in one public utility service area, only to be replaced by a new large plant of equal load size in another public utility service area. This analysis, however, assumes that if loads do not grow, requirements customers likely would be able to serve NLSLs by dedicating existing resources (as allowed under existing contract provisions) without requiring BPA to build new resources. Therefore, only net growth in industrial loads is analyzed for NLSLs.

The analysis evaluates the projections of load growth by SIC for expected NLSLs using two studies of plant-specific electric energy consumption in the Northwest. The result is an estimate of the percentage of load growth for each SIC that will occur as NLSL. The percentages are applied to the

SIC-specific growth projections from the Joint BPA-Council Medium Case forecast to derive the high case NLSL estimates. Tables 5.3.1-4 show the high case NLSL estimates by industry (SIC). Industries not reported are forecast to produce no NLSLs between 1988 and 2008.

The Joint BPA-Council Medium Case forecast is calculated based on the PF rate, so the analysis results in an alternative case NLSL estimate also based on the PF rate.

5.3.1.2. Estimated Industrial Loads for No Action Alternative

The No Action Alternative or Base Case estimate begins with the alternative case NLSL load projection. For the No Action estimate, the NLSLs from the alternative case projection are assumed to be charged a 7(f) rate based on the NR rate, which is a rate increase of about 46 percent over those in the alternative case. The response to such a rate increase of the industries projected to produce NLSLs (see Tables 5.3.1-4) is determined using the Joint BPA-Council Industrial Model. The model is run with a set of rates based on the PF rate and with another based on the NR rate. The response by industry is summarized as an electric energy price elasticity, which measures the percentage change in load divided by the percentage change in rate. The elasticities and the approximately 46 percent rate increase are applied to the alternative case NLSL projections by industry to derive the Base Case projections shown in Tables 5.3.1-5.

5.3.2. Environmental Effects

Environmental implications arise due to changes in the need for new resources. Other implications would also be linked to the types of industries that increased in size due to the alternative.

5.3.2.1. Future Resource Development

The need for further Pacific Northwest resource development would be increased if the alternative increases NLSL load. These resources would be developed by BPA unless utilities exercised current contract rights to dedicate specified resources to serve NLSLs. The electric energy price elasticities are negative, showing that industries in general will reduce loads when rates increase. Industries may reduce load by increasing energy efficiency (conservation); substituting other forms of energy for electric energy; installing self-generation or cogeneration facilities; decreasing their production levels; or relocating. The elasticities do not indicate how loads would be reduced, except that over half the reduction in paper industry NLSLs would occur as a result of cogeneration or self-generation.

Table 5.3.5 shows that BPA estimates that 290 MW of load as defined in the NLSL provisions in the Northwest Power Act and the PSCs would occur in preference customer utility service areas by 2008 if the lower rate were available. Table 5.3.5 also shows that BPA estimates that 225 MW of NLSL will occur in preference customer service areas by 2008 under the existing PSCs.

Table 5.3.1

PULP AND PAPER INDUSTRY
(SIC 26)
NLSL PROJECTIONS FOR BASE AND ALTERNATIVE

Period	Base NLSL Growth	Altern/High NLSL Growth
1988-1991	22 MW	30 MW
1992-1996	41	56
1997-2008	100	138
Total:	163	224

Key Parameters:
Percentage of load growth under the PF rate that is NLSL is 82%.
Price elasticity = 0.2
Projected cogeneration = 20%.

Table 5.3.2

CHEMICALS
(SIC 28)
NLSL PROJECTIONS FOR BASE AND ALTERNATIVE

Period	Base NLSL Growth	Altern/High NLSL Growth
1988-1991	11 MW	12 MW
1992-1996	9	9
1997-2008	24	25
Total:	44	46

Key Parameters:
Percentage of load growth under the PF rate that is NLSL is 63%.
Price elasticity = 0.07.
Projected cogeneration = 0.

Table 5.3.3

PRIMARY METALS
(SIC 33)
NLSL PROJECTIONS FOR BASE AND ALTERNATIVE

Period	Base NLSL Growth	Altern/High NLSL Growth
1988-1991	0 MW	0 MW
1992-1996	9	10
1997-2008	0	0
Total:	9	10

Key Parameters and Assumptions:
Judgmental call, based on current knowledge of the industry.
Price elasticity = 0.15.
Projected cogeneration = 0.

Table 5.3.4

MINING
(SIC 10)
NLSL PROJECTIONS FOR BASE AND ALTERNATIVE

Period	Base NLSL Growth	Altern/High NLSL Growth
1988-1991	0 MW	0 MW
1992-1996	9	10
1997-2008	0	0
Total:	9	10

Key Parameters and Assumptions:
Judgmental call, based on current knowledge of the industry.
Price elasticity = 0.15.
Projected cogeneration = 0.

Table 5.3.5

TOTAL
ALL INDUSTRIES
NLSL PROJECTIONS FOR BASE AND ALTERNATIVE

Period	Base NLSL Growth	Altern/High NLSL Growth
1988-1991	33 MW	42 MW
1992-1996	68	85
1997-2008	124	163
Total:	225	290

Key Assumptions:
This table is the sum total of the previous tables.

Sources:

Bonneville Power Administration and the Northwest Power Planning Council, Forecast of Electricity Use in the Pacific Northwest, November 1988.
Dun and Bradstreet, Major Industrial Plant Database, 1988.
Bonneville Power Administration, Ten Largest Electricity Consuming Manufacturing Plants, 1985.
Division of Contracts and Rates, Bonneville Power Administration, "Final Modified SL-87 Rate Projections," December 1988.

This results in an increase of 65 MW in the loads for which BPA must plan firm resources. This amount is considered insignificant, because it would add only slightly to BPA's overall need to acquire resources.

5.3.2.2. Effects Related to Type of Industry

Of the 290 MW of NLSLs projected for the alternative, 224 MW is forecast to occur in the pulp and paper industry. That amount represents slightly more than 80 percent of the load growth forecast for that industry between 1988 and 2008. Such a high NLSL percentage is not unreasonable, since expansions in the pulp and paper industry historically occur in increments of 10 MW or more.

The Base Case estimate indicates that if the pulp and paper industry is charged the NR rate instead of the PF rate for NLSLs, the industry will grow by roughly 61 MW less than in the high case. Of this 61 MW of reduced load, approximately 40 MW would be due to a greater use of cogeneration in new or expanding pulp and paper plants. The remaining 21 MW would be due to other reasons, including conservation or the decision to locate the new plants or expansions elsewhere.

The other industries forecasted to experience NLSL growth are chemicals, primary metals (excluding the DSIs), and mining. These industries account for about 22 percent of all NLSLs projected in the high case. These industries are relatively insensitive to a new resource-based rate, primarily because the economics of using cogeneration, conservation, and fuels other than purchased electricity are not favorable unless electric rates to such consumers are higher than the new resource-based rate.

Pulp and Paper

Kraft and Bleached Sulfite Pulp

The chemicals associated with the production process include chlorine, chlorine dioxide, caustic soda, soda ash, saltcake, sulfur, lime, and sodium chlorate (used to produce chlorine dioxide for bleaching).

Kraft pulp mills use a chlorine bleaching process that results in trace levels of dioxin in the effluent, sludge, pulp, and a variety of consumer products that use bleached pulp. The EPA is currently conducting research to measure the discharge levels at all 104 bleach pulp mills in the United States to assess the risk to public health and to establish appropriate regulations. Canada and Sweden are also making efforts to find alternate technical processes and establish regulatory policies, which are likely to influence the United States. The National Institute of Occupational Safety and Health is currently conducting a study to examine the combined effects on the health of mill workers of dioxin and some 20 other chlorinated organic compounds identified as by-products of the chlorine bleaching process. (Pulp and Paper, April 1989.)

Another byproduct of bleach pulp mills is chloroform, which is released into the air at levels that pose a "serious risk of cancer," according to a recently published report by the EPA. Fifteen pulp mills in the Pacific Northwest are on this list (Oregonian, June 6, 1989). No policies have been developed, but the report and the data upon which it is based will very likely be taken into account in the current debate in Congress on the renewal of the Clean Air Act.

Some expansion of existing mills is possible, but because of the above environmental concerns over effluents, there is a movement away from this chemical process towards the thermomechanical pulping process, which is relatively environmentally benign. In anticipation of likely environmental legislation, existing chemical bleaching pulp mills are gradually substituting the more benign sodium chlorate for chlorine in the bleaching process. Future chemical bleaching mills will very likely be based upon the sodium chlorate process or on the hydrogen peroxide or oxygen technologies.

Thermomechanical Pulp (TMP)

Environmental concern over the chemical bleaching process is resulting in a movement into TMP production of newsprint. New paper production plants are likely to utilize this production process. The chemicals associated with the production process include chelating agents such as the frequently used ethylenediamine tetraacetic acid (EDTA) and the less frequently used sodium tripolyphosphate (STPP). To control/disperse the pitch content of wood chips, alum and sodium lignosulfonate are commonly used; and talc and calcium carbonate are being investigated on a trial basis. Sodium hydrosulfite is used for bleaching (Pulp & Paper, June 1989).

Papermaking

Papermaking chemicals include calcium carbonate, kaolin, titanium dioxide, and starch. Also used in papermaking are finish chemicals such as alum, dyes, acoids, alkalines, biocides, polyacrylamides, and surfactants. Synthetic binder latex, acrylics, and plastic pigments are used as coating additives.

Chemicals

Sodium Chlorate

Sodium chlorate is a type of chemical that could be produced in NLSL plants. Its major market is the pulp and paper industry, which is driving the growth in demand for this chemical. Other uses include the production of ammonium perchlorate, an oxidizer for the uranium industry, and defoliants. A number of compounds, listed below, are either used in the production of sodium chlorate or generated as by-products, all of which may potentially affect the environment by their fire hazards and toxic fumes. Other issues associated with sodium chlorate production include the disposal of sludge, which contains sodium chlorate, sodium chloride, and sodium bichromate.

The most significant chemicals likely to be present at a sodium chlorate plant have been rated by the National Fire Association on a scale of 0-4, with "0" implying safest and "4" implying most dangerous. These chemicals are rated in terms of their potential for danger in fire or explosive conditions in three areas, consisting of health, reactivity to other substance, and flammability.

Sodium chlorate is rated 1 for health, 2 for reactivity, and 0 for flammability. When mixed with combustible materials, sodium chlorate becomes a fire hazard that yields toxic fumes when burning.

Sodium chloride (common salt) isn't rated by the NFA, but is used to make sodium chlorate.

Sodium bichromate, a raw material, is rated 1 for health, 1 for reactivity and 0 for flammability. This chemical is a concern because chromium and chromium compounds are known carcinogens at certain dosages.

Sodium hydroxide (lye) is rated 3 for health, 0 for reactivity, and 0 for flammability. This chemical is used first with sodium carbonate to treat salt that has been dissolved in water. The chemical reaction results in some materials that are disposed of in a landfill, with the rest moving as a scrubbing agent to reduce the levels of chlorine gas formed as chlorate crystals are produced.

Hydrogen, a byproduct, is rated 0 for health, 0 for reactivity, and 4 for flammability, since hydrogen forms explosive mixtures with air. Nitrogen gas can be added to the hydrogen to negate the flammability.

Chlorine gas, a byproduct, has a health rating of 3 and is rated 0 for reactivity and flammability.

Steel/Silicon

Smoke and dust emissions from electric arc melting furnaces must be collected. The dust contains elements of lead, cadmium, and chromium and is classified as a hazardous waste. Noise levels must also be restricted. The other prominent environmental concern is how cooling water is treated. (Telephone conversation with Art Robare, Electrical Engineer, Cascade Steel Rolling Mills.)

Copper

Restrictions on sulfur dioxide (SO_2) air emissions for the copper industry have caused a shift in copper smelting and refining technology away from pyrometallurgical processes to hydrometallurgical processes. If a new copper complex is constructed that is a NLSL, it will more than likely use hydrometallurgical processes based on solvent extraction and electrowinning. Such processes have comparatively few environmental problems. They do have effluents and solid wastes that must be controlled, including arsenic, cadmium, lead, zinc, nickel, and copper.

Gold

Leaching gold ores with cyanide is a common processing technique in gold mining. Special precautions and monitoring procedures must be used to avoid contaminating the surrounding environment with cyanide. Reclamation of the mine site after deposits are depleted is also of high environmental priority. (Applies to all the other metals as well, except steel.)

Silver

Silver is normally mined and processed in association with lead, copper, or gold. See those metals for the associated environmental aspects.

Lead

Large electric loads of over 10 aMW are not likely to occur in this metal industry. The lead industry does have significant environmental characteristics, however. The blood-lead levels of mine and smelter workers must be monitored closely. The EPA under the Clean Air Act and the Clean Water Act regulates lead particulate emissions, effluents, and SO_2 emissions.

Environmental Impacts

5.4. NLSLs - Increase Constraints

Under this alternative, BPA's preference customers are assumed to pay the NR rate for all industrial load growth including amounts under 10 MW. This approximates a more extreme marginal cost pricing for industrial load growth than under current statutes and PSCs. The analysis determines the impact on regional preference customer loads.

5.4.1. Method of Analysis

The analysis uses the Joint BPA-Council Medium Case forecast for public utility industrial loads as a benchmark to assess the potential impacts of this alternative. The Joint Forecast assumes no NLSL constraints, and therefore is based exclusively on the PF rate. The analysis consists of two scenarios. In the first (the targeted approach), preference customers pass through all NR rate costs to new plants and facility expansions. In the second (the melded approach), preference customers meld their wholesale cost of power so all industrial loads, both existing and new, bear a portion of the higher NR rate.

5.4.1.1. Targeted Approach

The analysis for the targeted approach uses the same method as the Base Case described in Alternative 5.3, including the assumptions about electric energy price elasticity and the 46 percent difference between the NR rate and the PF rate. See Table 5.4.1.

5.4.1.2. Melded Approach

This approach analyzes the Joint Forecast at the aggregate level with no sector breakdown. The rate increase following this approach would be much smaller than the 46 percent used for the targeted approach, since the rate is spread over all industrial loads. A composite electric energy price elasticity is calculated by computing a weighted average of industrial elasticities from the Joint Industrial Model (see alternative 5.3). The calculated rate increases and composite electric energy price elasticity are applied to the Joint Forecast's projection of total public utility industrial loads to derive the load decreases caused by the NLSL constraints. See Table 5.4.2.

5.4.2. Environmental Effects

5.4.2.1 Future Resource Developments

Need for future resource development may decline under the alternative if it decreases NLSL growth. Implementing NLSL constraints for all industrial load growth is estimated to result in a decrease of between 73 MW (melded approach) and 116 MW (targeted approach) in public utility sales by 2008. See Tables 5.4.1 and 5.4.2. Cogeneration is the primary cause of the difference between these two assessments.

5.4.2.2 Effects Related to Type of Industry

In the targeted approach, the pulp and paper industry would react by switching electrical energy requirements away from public utilities to cogeneration. Industries such as the lumber and wood industry, which are forecast to use a declining amount of energy over the 20-year period, are estimated to be largely unaffected by the increased NLSL constraints (see Table 5.4.1). However, in the melded approach, rates for these industries are estimated to increase, causing their loads to decline slightly more than they would have otherwise (2-3 percent difference by 2008).

In general, the load reductions caused by the NLSL constraints are expected to result for the same various reasons explained in Alternative 5.3.

Table 5.4.1

CHANGE IN PREFERENCE CUSTOMER LOADS FOR NLSL ALTERNATIVE 5.4: TARGETED APPROACH (average annual megawatts)

	Base Load Growth	NLSL Constrained Load Growth	Change in Load Growth
1988-1991:			
Lumber and Wood	-25	-25	0
Pulp and Paper	37	26	-11
Chemicals	19	18	-1
Primary Metals	36	34	-2
Other Industries	38	34	-4
Total:	105	87	-18
1992-1996:			
Lumber and Wood	-24	-24	0
Pulp and Paper	69	49	-20
Chemicals	14	14	0
Primary Metals	6	5	-1
Other Industries	56	49	-7
Total:	121	93	-28
1997-2008:			
Lumber and Wood	0	0	0
Pulp and Paper	169	120	-49
Chemicals	40	39	-1
Primary Metals	25	23	-2
Other Industries	161	143	-18
Total:	395	325	-70
Total all industries 1988-2008:	621	505	-116

Table 5.4.2

CHANGE IN PREFERENCE CUSTOMER LOADS FOR NLSL ALTERNATIVE 5.4: MELDED APPROACH

Year	A Percent of Total Bill at NR Rate (%)	B Average Ind. Rate Increase (%)	C Percent Change in Total Base Load (%)	D Total Base Load (MW)	E Absolute Change in Total Base Load (MW)
1991	5	2.3	-0.6	2078	-12
1996	10	4.6	-1.2	2198	26
2008	24	11.0	-2.8	2594	-73

Assumptions: In all years, rate increase due to NR rate = 46% and average industrial price elasticity = 25%.

Notes: B = A * 46%, where A represents the portion of total public industrial loads for which public utilities would be billed the NR rate instead of the PF rate, and 46% is the rate increase due to the NR rate.

C = B * 25%, the composite electric energy price elasticity for public utility industrial loads.

E = C * D.

Source: Bonneville Power Administration and the Northwest Power Planning Council, Forecast of Electricity Use in the Pacific Northwest, November 1988.

OTHER REQUIRED ENVIRONMENTAL CONSIDERATIONS

In addition to responsibilities under the National Environmental Policy Act, Federal agencies such as BPA are required to carry out the provisions of other Federal environmental laws and regulations to the extent that they apply to the proposed actions under consideration. Environmental analysis elsewhere in Chapter 4 and in the technical appendices has addressed most of these to the extent the scope of this EIS has implications in such areas, to wit:

1. Environmental Policy.
2. Endangered and Threatened Species and Critical Habitat.
3. Fish and Wildlife Conservation.
4. Heritage Conservation.
5. State, Areawide, and Local Plan and Program Consistency.
6. Recreation Resources.
7. Global Warming.

In addition, BPA has generally considered the following:

1. Floodplains.
2. Wetlands.
3. Farmlands.
4. Structures in Navigable Waters (Permits for).
5. Permit for Right-of-Way on Public Lands.

The broad policy alternatives considered in this EIS would only impact such areas through later programs or decisions on the development or changed operation of electric power generating or transmission facilities. Such actions, if undertaken by BPA, would require separate NEPA analysis of specific proposals. BPA's planned EIS on its Resource Program as well as any site-specific NEPA documents would cover the effects of new generating facilities. Also, the SOR EIS, jointly sponsored by BPA, the U.S. Bureau of Reclamation and the U.S. Army Corps of Engineers, will address the effects of changed hydro operations for power generation as well as other purposes.

The actions considered in this EIS do not have implications for the following:

1. Coastal Management Program Consistency.
2. Permit for Discharges into the Waters of the U.S.
3. Energy Conservation at Federal Facilities.
4. Pollution Control at Federal Facilities.

CHAPTER 5

List of Preparers of the EIS

CHAPTER 5

LIST OF PREPARERS OF THE ENVIRONMENTAL IMPACT STATEMENT

Name	EIS Responsibility	Qualifications
BPA		
Pat Barton	Conservation Analysis	B.A., Economics; M.S., Eng.; 5 yrs. BPA, demand-side mgmnt.
Shephard Buchanan	Resource Planning Analysis	M.S. Resource Economics; BPA, 9 yrs. Economist; Resource Planning, Policy Analysis Section.
Mike Bull	Conservation Analysis	B.A., Mathematics; M.S., Economics; BPA, 10 yrs., Conservation Planning.
Robert Clark	Industrial Analysis	M.S., Economics; BPA, 10 yrs; Industrial load forecasting and metal industry analysis. Industry Economist.
Charles Combs	Contractual Analysis	B.A., History; J.D.; BPA, 10 yrs. Customer Power Sales Contracts.
Mark Ebberts	Conservation Transfers Analysis	M.S. Economics; BPA, 7 years (Industry Economist) Resource Planning. Project lead for conservation transfers.
Elizabeth Evans	Conservation Analysis	B.S. Botany; MUP, Planning, PhD., Ecology; BPA, 5 yrs., Coordination & Review and Program Analysis Section.
Maureen Flynn	DEIS Project Manager	B.S., Psy.; J.D.; BPA, 12 yrs. Customer power sales and transmission contracts and policy.
Roy Fox	Management	B.S., Economics; BPA, 11 yrs. Natural Resouces Economist; 1 yr. Conservation Program Manager; 6 yrs. Manager Coordination and Review.

Name	EIS Responsibility	Qualifications
BPA		
David Gilman	Transmission-related System Engineering Analysis	B.S. Electrical Engineering; BPA, 21 yrs. Transmission System Planning.
Douglas Hanlon	Conservation Transfers Analysis	B.S., Civil Engineering; BPA, 12 yrs. Hydraulic Engineer; 11 yrs. power sales, transmission, and conservation contracts.
Diana Jones	Management--System Analysis Model Analysis, Reserves Analysis	B.S., Electrical Engineering; BPA, 13 yrs. Hydraulic Engineer; 5 yrs. Electrical Engineer; 7 yrs. Supervisory Electrical Engineer.
Stanley Kusaka	DSI Analysis	M.B.A.; BPA, 12 yrs. Power Forecasting.
Robert Lamb	Management--System Analysis Model Analysis	B.S., Gen/Science; M.S., meteorology; BPA 12 yrs., hydrometeorology, power capabilities and power resources planning.
Robyn MacKay	Fisheries Analysis	B.S. Mech. Eng.; BPA, 5 yrs.; Hydro Power Capabilities Branch; 2 yrs. F&W Div.
Jacilyn Margeson	DSI and Reserves Analysis	B.S. Political Science; 10 yrs. BPA; 8 yrs. rate design and analysis.
John McConnaughey	Rate Impacts Review	PhD., M.S., Economics; BPA, 11 yrs.; 8 yrs. Load Forecasting; 3 yrs. Rate Analysis; Bureau of Standards, 4 yrs, Energy Conservation Consulting and Research.
Jonathan S. Mills	Fish and Wildlife Policy Analysis	B.A., Political Science; MPP (Master of Public Policy); BPA, 5 yrs., fish and wildlife analysis.
Sharron Monohon	System Analysis Model Analysis	B.S., Mathematics; BPA, 7 yrs. Power System Planning.

Name	EIS Responsibility	Qualifications
BPA		
John O'Donnell	Computer Data Transfers	B.S., Industrial tech. & computer sciences; B.A., Business admn.; BPA, 7 yrs, ADP coordination and support.
Kevin O'Sullivan	Industrial Analysis	B.A. History and Economics/ Mathematics; M.A., Economics; BPA, 3 yr. Industry Economist.
Tom Pansky	Fish and Wildlife Policy Analysis	B.A., Philosophy/Physics, Middleburg College. Manager, Northwest Environmental Data Base, 6 yrs.
Terrin Pearson	Power Operations Analysis	B.S., Physics; 19 yrs., BPA Division of Power Supply.
Audrey Perino	Management--Resource Planning Analysis	B.A. Mathematics; M.A. Economics; BPA, 7 yrs Industry Economist doing Resource Planning Analysis.
Martha Pinkstaff	Writing, Editing	B.A., Economics; BPA, 10 yrs., Rate and cost analysis; power sales and environmental issues.
Roger Rice	Computer Processing for FISHPASS Analysis	A.A., Business Mgt.; BPA, 10 yrs.; Div. of Power Forecasting, 4 yrs.; Div. of F&W, 5 yrs.
Randy Russell	Residential Exchange Issues	B.A., M.S. Economics; BPA, 3 yrs. Rates Analyst, 5 yrs. Residential Exchange Program Policy and Analysis.
Roger Schiewe	Review of System Operations Analysis	B.S. Mathematics; 20 yrs. BPA Division of Power Supply.
Randy Seiffert	Coordination of DSI Analysis; Air, Land and Water Impacts; Resource Operations Effects	B.S., Chemical Engineering; BPA, 13 yrs. environmental issues.
Brian Silverstein	Transmission-related System Engineering Analysis	M. Eng., Electric Power; BPA 12 yrs. transmission planning.

Name	EIS Responsibility	Qualifications
BPA		
Paul Spies	Aluminum DSI Analysis	B.S. Biology; M.S., Resource Economics; 3 yrs., BPA Industry Economist.
Helen Stevens	DSI Contractual Analysis	B.S., Economics; BPA, 15 yrs., Economist (Rates) 3 yrs.; Public Utilities Specialist (Rates, conservation, Power contracts), 12 yrs.
Sam Sugiyama	Industrial Analysis	Ph.D., Economics; B.A., Economics and Mathematics; BPA, 8 yrs. industrial analysis and modeling.
Terry P. Thompson	Computer Processing for SAM Analysis	B.S., Electrical Eng.; BPA, 23 yrs., Power Planning, Modeling.
Nandranie Tuck	Processing Biological Assessment	B.S., Geog.; MPA Prog.--Public Policy Analysis; Metro, 1 yr. land use planning; COE, 5 yrs., EIS Mgr.; BPA, 3 yrs. EIS Mgr.
Peter West	Employment and Related Socioeconomic Analysis	B.A. Econ.; M.S. Ag. & Resource Econ.; OSU/USDA, 1 yr. Resource Economist; BPA, 6 yrs., regional economics, econometrics, economic and demographic forecasting.
John Wilkins	Employment, Population, and Related Data	B.S. Agric. Economics; BPA, 13 yrs.; Agricultural and Industrial economics.
Donald Wolfe	Contractual Analysis FEIS Project Manager	B.A., Psychology; J.D.; BPA, 9 yrs. Environmental analysis, energy conservation & power sales issues.
Contractors & Consultants		
Carol Brodsky, Brodsky & Hillman	Document Production, Writing, Editing	10 yrs. professional writing and publishing, Federal agency environmental documents.

Name	EIS Responsibility	Qualifications
Contractors & Consultants		
Lawrence A. Dean	Contractual and System Operations Analysis	BPA, retired; 30 yrs. PNW coordinated system operations and planning.
Franklin Neubauer, Advanced Data Concepts	Conservation Analysis	3 yrs, conservation modeling; BPA assignment, 1.5 yrs.
Terence L. Thatcher, Attorney at Law	Fish and Wildlife Policy Analysis	7 yrs, Counsel for National Wildlife Federation, Oregon Office, PNW energy and fish and wildlife issues.

CHAPTER 6

List of Agencies, Organizations and Persons Receiving the EIS

CHAPTER 6

List of Agencies, Organizations and Persons to Whom Copies of the Statement Are Sent */

FEDERAL AGENCIES

U.S. Army Corps of Engineers, North Pacific Division

U.S. Attorney's Office

U.S. Department of Commerce
National Marine Fisheries Service
National Oceanic & Atmospheric Administration

U.S. Department of Energy
Federal Energy Regulatory Commission
Public Reading Room IE-190
Western Area Power Administration

U.S. Department of the Interior
Bureau of Indian Affairs
Bureau of Indian Affairs, Mission Valley Power
Bureau of Indian Affairs, WAPATO Irrigation Project
Bureau of Land Management
Bureau of Reclamation
Fish & Wildlife Service
National Park Service
Office of Environmental Affairs
Pacific Northwest Region, Office of the Secretary

U.S. Environmental Protection Agency
Region 8
Region 10

U.S. Navy
Jim Creek Naval Radio Station
Puget Sound Naval Shipyard
Western Division Code 0224, Naval Facilities Engineering Command

*/ This list doe not include those potentially interested parties to whom BPA mailed a notice of availability of the statement.

STATE OF CALIFORNIA

STATE AGENCIES

State Clearinghouse
Department of Fish & Game
Energy Commission

LOCAL/REGIONAL

City of Healdsburg

STATE OF IDAHO

STATE AGENCIES

Department of Fish & Game
Department of Health & Welfare, Division of Environmental Quality
Public Utilities Commission

LOCAL/REGIONAL

City of Albion
City of Burley
City of Delco
City of Heyburn, Board of Trustees
City of Heyburn, Department of Electricity
City of Idaho Falls, Electric Division
City of Minidoka
City of Plummer
City of Rupert
City of Soda Springs

STATE OF MONTANA

STATE AGENCIES

Governor's Office, Interagency Review Team
IGR Clearinghouse, Office of Budget & Program Planning
Department of Health & Environmental Sciences

LOCAL/REGIONAL

City of Troy Power & Light

STATE OF NEVADA

STATE AGENCIES

Office of the Governor, State Planning Coordinator

STATE OF OREGON

STATE AGENCIES

Department of Energy
Department of Environmental Quality
Department of Fish & Wildlife
Office of the Governor, Intergovernmental Relations Division
Oregon Farm Bureau
State Clearinghouse

LOCAL/REGIONAL

City of Ashland
City of Bandon
City of Cascade Locks
City of Drain
City of Forest Grove, Department of Power & Light
City of McMinnville, Department of Water & Light
City of Milton-Freewater, Department of Light & Power
City of Monmouth
City of Portland, Attorneys Office
ORE-IDA Regional Planning & Development Association

STATE OF UTAH

STATE AGENCIES

Division of State History
Office of Energy

STATE OF WASHINGTON

STATE AGENCIES

Department of Ecology
Department of Fisheries
Office of Energy

LOCAL/REGIONAL

City of Blaine
City of Centralia, Department of Light
City of Cheney, Department of Light
City of Chewelah
City of Coulee Dam, Department of Light
City of Ellensburg
City of Port Angeles, Department of Light
City of Richland, Department of Energy Services
City of Sumas
City of Tacoma, Department of Public Utilities
County of Grays Harbor, Regional Planning Commission
Town of Eatonville
Town of Fircrest
Town of Milton
Town of Steilacoom
Town of Waterville

STATE OF WYOMING

STATE AGENCIES

Office of the Governor, State Planning Coordinator

INTEREST GROUPS

Columbia River Fishermen's Protective Union
    Legislative & Conservation Committee for Columbia River Fishermen's Protective Union
Columbia River Inter-Tribal Fish Commission
Fair Electric Rates Now
Forelaws on Board
Friends of the Earth
Mountaineers
National Wildlife Federation
Natural Resources Defense Council
Northwest Conservation Act Coalition
Seattle Audubon Society

LIBRARIES

City of Boise Public Library
College of Southern Idaho Library
Fort Vancouver Regional Library
Idaho State University, Library Documents Division
Library Association of Portland
Montana State University, Renne Library
Oregon State University, Kerr Library Documents Division
Portland State University, Regional Depository Millar Library
Seattle Public Library
Southern Oregon State College Library
Spokane Public Library
State of California Regional Depository Library
State of Idaho Library
State of Montana Library
State of Oregon Library
State of Utah Library
State of Wyoming Library
Tacoma Public Library
University of Idaho, U.S. Documents Library
University of Montana, Mansfield Library
University of Oregon, Library Documents Section
University of Washington, Suzzallo Library Government Publications
Washington State Library
Washington State University, Library Documents Section

UTILITIES, UTILITY ASSOCIATIONS, AND OTHERS

Bob Despain
Archer Hardwick
Anker Larson
Marvin Lewis
Dan Meek
Ed Merrill
Mark C. Naulty
Joan Naulty
Michael Rossotto
Jack Thoreson
R.E. Thoreson
Richard D. Williams

ACPC Incorporated
ALCOA
Alder Mutual Light Company
Alumax Incorporated
AMAX Magnesium Corporation
Architectural Association
Atochem North America
Benton County PUD No. 1
Benton Rural Electric Association
Big Bend Electric Coop Incorporated
Blachly-Lane County Coop, Electric Association
Bountiful City Light & Power, Power Resources
Canby Utility Board
Central Electric Coop, Incorporated
Central Lincoln PUD
CH2M Hill
Chelan County PUD No. 1
Chem Safe Incorporated
Citizens Utilities Company, Idaho Division
Clallam County PUD No. 1
Clark Public Utilities
Clatskanie County PUD
Clearwater Power Company
Colockum Transmission Company Incorporated
Columbia Aluminum Corporation, Goldendale Smelter
Columbia Basin Electric Coop Incorporated
Columbia Falls Aluminum Company
Columbia Inspection
Columbia Power Coop Association
Columbia River PUD
Columbia Rural Electric Association Incorporated
Consolidated Irrigation District 19
Consumers Power Incorporated
Coos County Board of Commissioners
Coos Curry Electric Coop Incorporated
Cowlitz County PUD No. 1

Direct Services Industries Incorporated
Douglas County PUD No. 1, Power Operations
Douglas Electric Coop Incorporated
East End Mutual Electric Company Limited
Elmhurst Mutual Power & Light Company
Emerald PUD
Eugene Water & Electric Board
Fall River Electric Coop
Farmers Electric Company
Ferry County PUD No. 1
Flathead Electric Coop Incorporated
Franklin County PUD No. 1
Georgia Pacific Corporation, Pulp & Chemicals Chlor Alkali
Gilmore Steel Corporation
Glacier Electric Coop Incorporated
Grant County PUD No. 2
Grays Harbor County PUD No. 1
Harney Electric Coop
Heller Ehrman White & McAuliffe, Direct Service Industries
Hood River Electric Coop
Idaho County Light & Power Coop Assoc Incorporated
Idaho Power Company
Imperial Irrigation District
Inland Power & Light Company
Intalco Aluminum Corporation
Intercompany Pool
Kaiser Aluminum & Chemical Corporation
Kaiser Aluminum & Chemical Corporation, Kaiser Center
Kaiser Aluminum & Chemical Corporation, Mead Plant
Kittitas County PUD No. 1
Klickitat County PUD No. 1
Kootenai Electric Coop Incorporated
Lakeview Light & Power Company
Lane Electric Coop Incorporated
Lewis & Clark College, Northwest School of Law
Lewis County PUD
Lincoln Electric Coop Incorporated
Lost River Electric Coop Incorporated
Lower Valley Power & Light Company
Mason County PUD No. 1
Mason County PUD No. 3
McCleary Light & Power
Mid Columbia PUD
Midstate Electric Coop
Missoula Electric Coop Incorporated
Modern Electric Water Company
Montana Power Company
Nespelem Valley Electric Coop Incorporated
Nickel Joint Venture
Northern Lights Incorporated
Northern Wasco County PUD

Northwest Aluminum Company
Northwest Power Planning Council
Ohop Mutual Light Company
Okanogan County Electric Coop Incorporated
Okanogan County PUD No. 1
Orcas Power & Light Company
Oregon Metallurgical Company
Oregon Trail Electric Consumers
Pacific Carbide & Alloys Company
Pacific County PUD No. 2
Pacific Northwest Generating Company
Pacific NW Utilities Conference Committee
Pacific Power & Light Company
PacifiCorp Electric Operations
Parkland Light & Water Company
Pend Oreille County PUD No. 1
Peninsula Light Company Incorporated
Port Townsend Paper Corporation
Portland General Corporation
Portland General Electric Company
Portland General Exchange Incorporated
Prairie Power Coop Incorporated
Public Power Council
Puget Sound Power & Light Company
Raft River Rural Electric Coop Incorporated
Ravalli County Electric Coop Incorporated
Reynolds Metals Company
Riverside Electric Coop Limited
Rural Electric Company
Salem Electric
Salmon River Electric Coop Incorporated
Seattle City Light
Sierra Pacific Power Company
Skamania County PUD No. 1
Snohomish County PUD No. 1
South Side Electric Incorporated
Springfield Utility Board
Tanner Electric Coop
Tillamook County PUD
Tri City Herald
Umatilla County PUD
Umatilla Electric Coop
Unity Light & Power Company
Utah Power & Light Company
Vanalco Incorporated
Vera Irrigation District No. 15
Vigilante Electric Coop Incorporated
Wahkiakum County PUD No. 1
Wasco Electric Coop Incorporated

Washington Public Power Supply System
Washington Rural Electric Coop Association
Washington Water Power Company
Wells Rural Electric Company
West Oregon Electric Coop Incorporated
Western Washington PUD Corporation, March, Mundorf & Pratt
Whatcom County PUD No. 1

CHAPTER 7 Glossary

CHAPTER 7

Glossary

Acronyms and Abbreviations

AC - See Alternating current
aMW - See Average megawatts
cfs - See Cubic feet per second
DC - See Direct current
DSI - See Direct-service industries
ECC - See Energy Content Curve
EIS - See Environmental Impact Statement
FCRPS - See Federal Columbia River Power System
FELCC - See Firm Energy Load Carrying Capability
FERC - See Federal Energy Regulatory Commission
GCP - See General Contract Provisions
IOU - See Investor-owned utilities
IP - See Industrial Firm Rate
kcfs - See kcfs - Thousand cubic feet per second
kWh - See Kilowatt-hour
MAF - See MAF - Million Acre Feet
MCS - See Model Conservation Standards
MW - See Megawatts
NLSL - See New Large Single Load
NR - See New Resources Rate
PCB - See Polychlorinated biphenyls
PF - See Priority Firm Rate
PNCA - See Coordination Agreement
PNUCC - See Pacific Northwest Utilities Conference Committee
PNW - See Pacific Northwest
POD - See Point of Delivery
POI - See Point of Interconnection
PUD - See PUD - Public Utility District
PURPA - See Public Utilities Regulatory Policy Act
QF - See Qualifying Facilities

Glossary of Terms

The words below are defined for the reader as they are used in this environmental impact statement.

AC - (see Alternating current)

aMW - (see Average megawatts)

Actual Computed Requirements - One of three types of Computed Requirements purchasing bases. See Appendix B.

Acid deposition - The combination of oxides of nitrogen and sulfur, in the air, with water, forming acid rain or snow, which may adversely affect water resources and plant and animal life.

Acre-foot - The volume of water that will cover an area of 1-acre to a depth of 1 foot.

Advance energy - Electric energy delivered at BPA's option to industrial customers in lieu of restricting Industrial Firm Power (power that is delivered to industries on a contract basis). This energy may be subject to later return if needed to meet BPA's firm loads. This arrangement improves the availability of service and results in greater sales revenues to BPA. See Appendix C for more detail.

Air basins - Defined areas which generally confine the air-borne pollutants produced within them. Air pollutants tend to circulate and mix together within a basin.

Alluvial fan - A low cone-shaped deposit of sediment laid down by a swift-flowing stream as it enters a plain or an open valley, commonly in dry regions with interior drainage.

Alternating current (AC) - Term applied to an electric current or voltage that reverses its direction of flow at regular intervals and has alternately positive and negative values, the average value of which (over a period of time) is zero.

Ambient air - Ambient air is the air surrounding a particular spot, such as a power plant.

Anadromous fish - Fish species that spawn and initially rear in fresh water, migrate and mature in the ocean and return to fresh water as adults.

Aquatic biota - The plant and animal life of a water body, considered as a total ecological entity.

Aquifer - Any geological formation containing water, especially one that supplies water to wells, springs, etc.

Artifact - An object of any type made by human hands. Tools, weapons, pottery, and sculptured and engraved objects are representative artifacts.

Automatic generation control - Regulation of the power output of electric generators within a control area in response to changes in load, system frequency, and other factors, so as to maintain the scheduled system frequency and interchanges with other control areas.

Average megawatts (aMW) - The average amount of energy (number of megawatts) supplied or demanded over a specified period of time.

Baseload - A load that varies only slightly in level over a specified time period. Also, a plant that is generally operated most efficiently at a relatively constant level of generation.

Benthic insects - Insects living on the bottom of reservoirs or streams.

Block slump - The (usually limited) downward displacement of a mass of earth as a unit, often caused by excessive soil saturation.

Boreal - Pertaining to the forest areas and tundras of the North Temperate zone and Arctic region.

Borrowing Techniques - Methods to move energy planned for certain time periods to other time periods. See Appendix C for details.

Bottom-ash - Uncombusted materials which accumulate in the bottom of a boiler and which must be removed and, generally, disposed of as solid waste.

Brackish - Containing some salt. Brackish water often results where fresh waters meet the ocean.

Buffering capability - The ability of a material to resist a change in pH (acidity or basicity) when an acid or base is added.

Bypass - Water released from a project which does not go through the turbines or over the spillway. Bypass may include leakage, navigation lock releases, and fish ladders.

cfs - (see Cubic feet per second)

Capacity - The amount of power that can be produced by a generator or carried by a transmission facility at any instant. Also, the service whereby one utility delivers firm energy during another utility's period of peak usage with return made during the second utility's offpeak periods; compensation for this service may be with money, energy or other services.

Capital costs - The costs to construct a power plant, including the costs of materials, permits, and interest on borrowing.

Cogeneration - The generation of power in conjunction with (usually) an industrial process, using waste heat from one process to fuel the other.

Composite retail rates - The average retail rates calculated for (1) all the publicly owned utilities and (2) all the investor-owned utilities in the Pacific Northwest.

Computed Requirements - A purchasing basis used by certain BPA customers that have significant resources of their own. BPA's Computed Requirements customers are Seattle City Light, Tacoma City Light, Grant County PUD, Douglas County PUD, Chelan County PUD, Pend Oreille PUD, Eugene Water and Electric Board, Cowlitz County PUD, Snohomish County PUD, Montana Power Company, Idaho Power Company, Pacific Power & Light Company, Portland General Electric Company, Puget Sound Power & Light and Washington Water Power Company. See Appendix B for a detailed explanation.

Contracted Requirements - One of three types of Computed Requirements purchasing bases. See Appendix B.

Cooperative - A private, normally nonprofit utility, operating within state law but essentially self-regulated by a board of directors elected from its membership.

Coordination Agreement - The Pacific Northwest Coordination Agreement (PNCA), signed in August 1964, is a 39-year contract between the Corps, Bureau, and BPA, and 14 of the area's generating utilities. Under this agreement, the Government and the participating utilities, public and private, agree to operate their projects as if all were owned by a single entity. The objective of such coordinated operation is to make optimum use of the water and storage resources of the region.

Council's Energy Plan - The Council's plan to encourage conservation and efficient use of electric power and the development of renewable resources within the Pacific Northwest. The Pacific Northwest Power Act mandated the development of the Energy Plan.

Critical period - That portion of the historical 40-year streamflow record which, when combined with draft of all available reservoir storage, will produce the least amount of energy, with energy being used according to seasonal load patterns.

Critical period average energy generation - The average amount of energy projected to be generated during a period (which can vary in length depending on the purpose of the planning) of extremely low streamflow. Used as a basis for resource planning.

Critical rule curve - A set of end-of-month reservoir contents which take the reservoir from full to empty during a critical period. Critical rule curves are used to guide reservoir operation during actual operation.

Crustaceans - Aquatic creatures such as barnacles and crabs, which have a segmented body, an exterior shell-like skeleton, and paired, jointed limbs.

Cubic feet per second (cfs) - A unit of measurement pertaining to flow of water. One cfs is equal to 449 gallons per minute.

Cultural resources - The nonrenewable evidence of human occupation or activity as seen in any district, site, building, structure, artifact, ruin, object, work of art, architecture, or natural feature that was important in human history at the national, state, or local level.

DC - (see Direct current)

DSI - (see Direct-service industries)

Dam passage - The percentage of fish which get from one side of a dam to the other alive.

Decremental cost - The cost that a utility could avoid by not operating a power plant; a utility's decremental cost is considered by some regulators to be a "fair" rate for the utility to pay for purchased power.

Deoxygenation - The depletion of dissolved oxygen in water.

Detailed Fisheries Operating Plan - A Columbia River hydroelectric system operation manual prepared by fish and wildlife agencies and Indian tribes for fish passage related to the mainstem Columbia River.

Dewater - (a) To remove water from a solution containing wastes in order to concentrate and then dispose of the wastes. (b) To divert or remove water from a stream or river channel in order to construct or rebuild dams and related hydroelectric facilities.

Direct current (DC) - Term applied to an electric current or voltage which may have pulsating characteristics, but which does not reverse direction at regular intervals.

Direct-service industries (DSIs) - Industrial customers, including aluminum smelters and other electrically intensive industries, that buy power directly from BPA.

Dispatch - The monitoring and regulation of an electrical system to provide coordination; or the sequence by which electrical generating resources are called upon to generate power to serve changing amounts of load.

Displacement - The substitution of less-expensive energy for more expensive thermal energy. Such displacement means that the thermal plants may reduce or shut down their production, saving money and often reducing air pollution as well.

Dissolved gas concentrations - The amount of chemicals normally occurring as gases, such as nitrogen and oxygen, which are held in solution in water, expressed in units such as milligrams of the gas per liter of liquid.

Distribution costs - Costs faced by a utility that sells electricity at retail to consumers, the costs of transporting the power from the transmission substation to the consumer.

Downstream migrant survival - The survival of an individual juvenile salmon or steelhead from the time it enters the mainstem Snake or Columbia Rivers, until it gets below Bonneville Dam.

Draft - Release of water from a reservoir, usually measured in feet of reservoir elevation.

Drawdown - The distance that the water surface of a reservoir is lowered from a given elevation as water is released from the reservoir (drafted).

Economy energy - Nonfirm energy that can be generated on a partially loaded generating unit, or purchases of energy, at a price less than decremental cost. Economy energy is unconditionally interruptible.

Electrostatic precipitators - Devices used to remove particulate air pollutants from an air stream by establishing an electric charge on the particles which then are attracted to an oppositely charged collector.

Emergence - Migration of hatched salmon fry up through the gravel of a redd preparatory to continuing their life cycle in open water.

Endangered - A plant or animal species which is in danger of extinction throughout all or a significant portion of its range because its habitat is threatened with destruction, drastic modification, or severe curtailment, or because of overexploitation, disease, predation, or other factors; federally endangered species are officially designated by the U.S. Fish and Wildlife Service and published in the Federal Register.

End-use consumer - A consumer that purchases power from a utility for its own use.

Energization - The point at which a completed energy facility is put into operation.

Energy - For electrical power marketing, expressed in kilowatthours.

Energy Content Curve (ECC) - A seasonal guide, which gives a 95 percent confidence of refill, for use of storage water from each reservoir operated by a party to the Pacific Northwest Coordination Agreement. See Appendix C.

Energy surplus - A condition in which a utility system can supply more energy than is demanded; the energy may be nonfirm, due to water conditions, or firm, due to excess generating capability.

Entrainment - The drawing of fish and other aquatic organisms into tubes or tunnels carrying water for cooling purposes into thermal plants or for generating purposes into hydroelectric plants. Entrainment increases mortality rates for those organisms.

Environmental Impact Statement (EIS) - A document prepared by a Federal agency on the environmental impact of its proposals for legislation and/or other major actions significantly affecting the quality of the human environment. EISs are used as tools for decisionmaking and are required by the National Environmental Policy Act of 1969.

Equilibrium values - For the projection of BC Hydro's retail power rates for the EIS, the rates that reflect an economic equilibrium of supply and demand, considering the cost to supply the power (less revenues from secondary sales) and the loads.

Estuary - A coastal inlet where salt water meets fresh water, as at a river's mouth.

Eutrophication - The increase of aquatic vegetation (at the expense of animal life) as more plant nutrients are supplied.

Export sales - The sales of electricity from one region to another.

Extraregional - Outside the Pacific Northwest.

FCRPS - (see Federal Columbia River Power System)

FELCC - (see Firm Energy Load Carrying Capability)

FGD - (see Flue-gas desulfurization)

Federal Base System - Resources consisting of hydroelectric facilities of the Federal government, as well as Washington Nuclear Project No. 1 and No. 2, and 70 percent of No. 3, part of the Hanford Nuclear Project, and a portion of the Trojan Nuclear Project, along with a few other miscellaneous power generating resources. BPA uses these resources to serve the firm energy loads of its customers. When BPA allocates power during periods of insufficiency, it is the Federal Base System resources that are used in the allocations formula.

Federal Columbia River Power System (FCRPS) - The hydroelectric dams on the Columbia River financed by the U.S. Treasury, which operate as a coordinated generation system, and for which BPA serves as the power marketer.

Federal Energy Regulatory Commission (FERC) - A Federal agency which reviews hydroelectric projects and submitted applications for operating licenses.

Firm Energy Load Carrying Capability (FELCC) - Total amount of firm, or guaranteed, electricity the coordinated power system can supply during each month of the operating year.

FELCC Shift - A planning action, under the Coordination Agreement, in which the hydrosystem generates more electricity in one year of the critical period while generating less in another year of the period. Usually FELCC is shifted into the first year of the critical period, resulting in lower reservoir levels. See Appendix C.

Fingerlings - Young or small fish, especially very small salmon or trout.

Firm - In the power industry, guaranteed or assured. May refer to a guaranteed supply of power, to guaranteed access to a means to transmit power, or, with reference to loads, to guaranteed service for a defined need. Usually defined for a given period of time.

Firm Energy Load Carrying Capability (FELCC) - The minimum level of energy that can be produced and shaped to load during the period it would take reservoirs to be drafted from full to empty under critical streamflow conditions.

Firm Power - Power guaranteed to be available at all times during the period covered by a commitment, even under adverse conditions, except for reason of certain uncontrollable forces or service provisions. Firm power is composed of either firm energy, firm capacity, or both.

Firm Resource Exhibit - For the utility power sales contract, a list of Firm Resources to be used by the customer in serving its own load. See Appendix B.

Fish and Wildlife Program - A program promulgated by the Power Planning Council to protect, mitigate, and enhance fish and wildlife. The Pacific Northwest Power Act mandated this Program.

Fish ladder - A series of ascending pools constructed to enable salmon or other fish to swim upstream around or over a dam.

Fish passage facilities - Features of a hydroelectric or other type of dam to enable fish to move around, through, or over them without harm.

Flaring - The practice of disposing of a waste combustible gas by burning it in a open flame without recovery of heat and, typically, at the top of a stack.

Flexible Energy - Firm energy that can be moved during months of an operating year. See Appendix C.

Flow rate - The volume of a fluid which passes a point in a defined channel per unit of time.

Flow regimes - The pattern of flow as it changes with time over the course of some specific time period.

Fluctuation zone - The area between the maximum and minimum water levels in a reservoir.

Flue-gas desulfurization - The process of removing sulfur dioxide and other oxides of sulfur from gases generated by combustion or some other process before they are discharged to the atmosphere.

Fly-ash - Particulate matter remaining after combustion of a material which is entrained into the gas stream, and which may in large part be captured by an air pollution control device and, generally, disposed as a solid waste. Fly-ash not so captured is discharged as particulate matter into the atmosphere.

Foodweb - The interlocking pattern of food chains that results from their interconnection with one another; a way of presenting the flow of energy through an ecosystem.

Forced outage - The unexpected failure of some part of the power system to perform its function.

Forebay - The portion of the reservoir at a hydroelectric plant which is immediately upstream of the generating station.

Fossil fuel - A combustible, carbonaceous material formed from the remains of ancient plants and animals. Common fossil fuels include coal, natural gas, and derivatives of petroleum such as fuel oil and gasoline.

Fuel conversion efficiencies - The ratio (commonly expressed in percent) of the heating value of the fuel used per unit time to the power output of a generating plant.

General Contract Provisions (GCPs) - Power sales contract provisions contain detailed information on charges, rates, delivery, equipment, billing, metering, and other provisions required by statute. These provisions are common to all BPA power sales contracts and are also contained in other BPA contracts. (All references to GCP Form PSC-2, dated 2/7/89. This version has one additional section which changed the numbers of some key GCPs, e.g., GCP 44 in Form PSC-1 [8/25/81] is now GCP-45.)

Geothermal (energy) - The heat energy available in the rocks, hot water, and steam in the earth's subsurface.

Groundwater - The supply of fresh water under the earth's surface in an aquifer or soil.

Head - The vertical height of the water in a reservoir above the turbine. The difference between the elevations of the reservoir and the tailrace at the foot of the dam.

Hydraulic residence times - The average travel time for a particle of water through a reservoir or other body of water.

Hydrocarbons - Chemical compounds containing hydrogen and carbon. Some hydrocarbons may become air pollutants. Some hydrocarbon air pollutants are carcinogenic, and some react with other air pollutants to form photochemical smog.

Hydroelectric - With reference to a power system, the production of electric power through use of the gravitational force of falling water.

Hydrology - The localized conditions relating to the occurrence, circulation, distribution, and properties of ground and surface waters.

Hydrostatic testing - The use of pressurized water to test a tank, pipeline, or other equipment for leaks.

Impoundment - The accumulation of water in a reservoir.

Incubation - The period between fertilization of an egg and its hatching.

Industrial Firm Rate - The Industrial Firm (IP) rate is for sales of Federal power to BPA's direct-service industrial (DSI) customers. The loads of the DSIs differ from typical utility amounts. The demand charges are time differentiated on both a daily and a seasonal basis. The energy charge is seasonally differentiated based on an analysis of the cost of seasonal hydro storage.

Instantaneous flow rate - The minimum amount of flow required (usually in terms of fish survival and functioning) at a given moment in time.

Interruptibility - The extent to which the flow of power can be stopped for a given period of time. By agreement, the supply of interruptible power can be shut off to a customer on relatively short (hours or a few days') notice.

Inundation - The flooding or covering up of an area with water. Inundation occurs when a reservoir is first filled.

Investor-owned utilities (IOU's) - Privately owned, for profit utilities whose programs are financed by private (nongovernment) investors in the utility's stocks and bonds. (In contrast to publicly owned utilities.)

Juvenile - The stage in the life cycle of anadromous fish when they migrate downstream to the ocean.

kcfs - One thousand cubic feet per second. A measure of speed and volume of water flow. (see Cubic feet per second)

Kilowatt-hour (kWh) - The common unit of electric energy equal to 1 kilowatt of power supplied to or taken from an electric circuit for 1 hour. A kilowatt equals 1,000 watts.

Larvae - The newly hatched, earliest stage of anadromous fish.

Leakage - An amount of water which leaks around a dam without passing through the turbines, spillway gates, or navigation locks.

Lockage - An amount of water which passes through the navigation locks and does not pass through the spillway gates or turbines of a dam.

Least cost mix of resources - The combination of generating (including conservation) resources that would meet a given amount of load at a given time or for a given period most economically.

Levelized - Of costs, a method of calculating equal, periodic payments or receipts from unequal cost data for the same time period, considering the time value of money.

Littoral zone - The shallow waters near the shore of a reservoir or lake.

Load - The amount of electric power or energy delivered or required at any specified point or points on a system. Load originates primarily at the energy-consuming equipment of the customers.

Load growth - Increase in demand for electricity.

Load management - Influencing the level and shape of the demand for electrical energy so that it matches resources available as well as long-run objectives and constraints.

Load profiles - Information on the shape of customers' demands for electricity over time.

Load/resource balance - The point at which the demand for electricity matches or balances the amount and type of resources available to serve that demand.

Low water years - Years in which less water than usual is received in a river system producing power from water flow. This is usually a consequence of reduced rain/snow fall over the fall and winter months.

MAF - Million Acre Feet - An acre foot is the volume of water needed to cover one acre of land one foot deep.

MW - (see Megawatts)

Marginal energy costs - For a generating resource, the cost to produce one more kilowatt-hour of electricity.

Megawatts (MW) - A megawatt is one million watts, an electrical unit of power.

Microclimate - The climate of a small area, as of houses, of plant communities, or of urban communities.

Mine-mouth - Used to refer to thermal generating plants located close enough to the fuel source (generally coal) that no long-distance fuel transport is necessary.

Model Conservation Standards (MCS) - A conservation program developed in accordance with the Pacific Northwest Power Act by the Northwest Power Planning Council to define and adopt cost effective conservation standards as one of the region's electric generating resources.

New Large Single Load (NLSL) - Any load associated with a new facility, and existing facility, or an expansion of an existing facility:

- which is not contracted for, or committed to, as determined by the administration, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979; and

- which will result in an increase in power requirements of such customer of 10 average megawatts or more in any consecutive 12-month period.

New Resources (NR) Rate - The New Resources rate schedule is available for sales of firm power to IOUs and New Large Single Loads.

Nitrogen supersaturation - A condition of water in which the concentration of dissolved nitrogen exceeds the saturation level of the water. Excess nitrogen can lead to bubbles of nitrogen in the circulatory systems of fish.

Nominal dollars - For economic analysis, dollars in the year specified, not adjusted for the effects of inflation or the time value of money.

Nonfirm Energy - Energy supplied or available under an arrangement which does not have the guaranteed continuous availability feature of firm power.

Northwest Power Planning Council (Regional Council, or Council) - The Pacific Northwest Electric Power and Conservation Planning Council, established by the Pacific Northwest Power Act. They are charged with devising a regional electric energy plan for the Pacific Northwest and a regional program to protect, mitigate, and enhance fish and wildlife in the Columbia River Basin. The Council is composed of two appointed representatives from each of the states of Oregon, Idaho, Washington, and Montana.

Northwest Power Pool (Power Pool) - An organization of Pacific Northwest generating utilities which have their systems interconnected and coordinated to supply power in the most economical manner for their combined load requirements and maintenance program.

Nutrient loading - The quantity of elements or compounds essential as raw materials for organism growth and development which are dissolved or suspended in a sample of water.

Offpeak hours - Period of relatively low system demand for electrical energy, as specified by the supplier (such as the middle of the night).

Operating Demand - The level in the DSI Power Sales Contracts which defines BPA restriction rights and the DSI's curtailment rights. The Operating Demand is divided into four quartiles, each with different restriction and curtailment rights. Under normal operating conditions and normal product markets, the DSIs will operate at between 75 percent and 100 percent of the Operating Demand.

Operating Plan - A plan prepared each year by the NWPP Coordinating Group, encompassing the July-June operating year, to determine how much load can be served with existing resources. Also, a term used in the DSI power sales contracts to refer to BPA annual plans to serve DSI load.

Operating year - As defined in the power sales contracts, the 12-month period from July 1 through June 30.

Outplantings - Fish hatched and initially reared in a hatchery, which are then planted into natural habitats to continue juvenile rearing.

Overburden - The topmost layers of soil. In this EIS, the 30-50' layers of soil stripped off to reveal coal seams in the process of strip mining.

PCB - (see Polychlorinated biphenyls)

PF rate - (see Priority Firm rate)

PURPA - (see Public Utilities Regulatory Policy Act)

Pacific Northwest (PNW) - For this EIS, the states of Washington, Oregon, and Idaho; the portion of Montana west of the Continental Divide; and areas in Montana, Nevada, and Wyoming surrounding coal plants that serve the PNW.

Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) - Signed into law December 5, 1980, the Act provides for coordinated planning of the Pacific Northwest's energy future, through a Regional Planning Council with representation from Oregon, Idaho, Montana, and Washington.

Pacific Northwest Utilities Conference Committee (PNUCC) - An organization composed of public and investor-owned utilities, formed under the Defense Production Act of 1950. Its primary responsibility is to consolidate the long-range power and resource forecasts of the West Group Area of the region.

Passage survival - The survival rate of migratory fish through, around, or over dams or other obstructions in a stream or river.

Peak capability - The maximum output of a generating plant or plants during a specified peak load period.

Peak loads - The maximum electrical demand in a stated period of time. It may be the maximum instantaneous load or the maximum average load within a designated interval of the stated period of time.

Peak reserves - Extra generating capacity available to meet unanticipated demands for power resulting from scheduled or unscheduled outages of regularly used generating capacity.

Percolation - The movement of water through the subsurface soil layers, usually continuing downward to the groundwater and water table reserves.

Photochemical smog - A type of air pollution resulting when sunlight induces chemical reactions of other pollutants, notably nitrogen dioxide and hydrocarbons. Elevated ozone levels are an indicator of photochemical smog since ozone is one of the products of the photochemical reaction.

Phytoplankton - The plant portion of the floating or weakly swimming organisms, often microscopic in size, in a body of water.

Planned Computed Requirements - One of three types of Computed Requirements purchasing bases. See Appendix B.

Plume - The discharge of gas and other pollutants into ambient air, or the discharge of polluted or heated water into a body of water from its source to the point where the discharge is no longer identifiable since it has mixed with the ambient air or the water.

Plunging flows - Water flow over a very steep surface or off of a precipice into a pool. This situation is one which produces high levels of dissolved gases in the water, such as nitrogen supersaturation.

Point of delivery (POD) - Point at which utility systems are connected with the primary purpose of one-way power delivery.

Point of Interconnection (POI) - Point in which utility systems are connected at which power can flow in either direction for power delivery (Point of Delivery), resource integration (wheeling), and system reliability improvement.

Polychlorinated biphenyls (PCBs) - A group of noncombustible synthetic insulating/dielectric fluids used in certain electrical equipment; found to be very persistent in the environment and strongly suspected of having carcinogenic effects.

Pool mortality - Death that occurs to a juvenile salmon or steelhead as it migrates through the pool or reservoir of a run-of-the river project.

Pre-emergent fry - Fish after they have hatched from their eggs but before they have left their incubation environment.

Predation - The capturing of prey as a means of maintaining life.

Preference customers - Cooperatives and public bodies (states, public utility district, counties, and municipalities, in the Northwest which have been given preferential rights by Congress to Federally generated hydroelectric power.

Prevention of significant deterioration (PSD) increment - Any one of several incremental changes in ambient total suspended particulate or sulfur dioxide concentrations established by the Environmental Protection Agency to protect existing air quality from being degraded significantly through new developments, such as construction and operation of a new air pollution source.

Priority Firm (PF) rate - The priority firm (PF) rate schedule is for sale of firm power to be used within the Pacific Northwest by public bodies, cooperatives, Federal agencies, and IOU's participating in the residential and small farm exchange under Section 5(C) of the Pacific Northwest Power Act.

Project outflow - The volume of water per unit of time downstream from a project.

Public Utilities Regulatory Policy Act (PURPA) - Enacted in 1978, it is the Federal legislation that requires utilities to purchase electricity from qualified independent power producers at a price that reflects what the utilities would otherwise have to pay for the construction of new generating resources.

PUD - Public Utility District (in Washington) or People's Utility District (in Oregon); a separate unit of government established by voters of a district to supply electric or other utility service.

Pumped storage - An arrangement whereby electric power may be generated during peak load periods by hydroelectric plants using water previously pumped into a storage reservoir during offpeak periods.

Qualifying Facilities (QFs) - Renewable and cogeneration resources developed under the Public Utilities Regulatory Policy Act of 1978.

Quartiles - The DSIs' electric operating demands are divided into four quartiles to which different contract provisions apply. See Appendix B for full explanation.

Real cost escalations - The increase in cost over a period of time due solely to the time value of money; that is, adjusted for price inflation.

Real discount rate - The factor used to compute the present value of a future amount, which adjusts solely for the time value of money and does not include price inflation.

Reclamation - The restoration of land to resemble its original condition or an acceptable substitute as to shape, vegetation, and wildlife; reclamation takes place after an area has been stripmined or after an energy facility has been built.

Record of Decision - The document notifying the public of a decision taken on a power project, together with the reasons for the choices entering into that decision. The Record of Decision is published in the Federal Register.

Recordation - The making of appropriate records (following National Park Service guidelines) to insure that a permanent record of a cultural resource's present appearance and context are made before the resource is disturbed through destruction, demolition, or inundation. Such a record might consist of written description, photographs, and so on.

Redds - Gravel nest created by female salmon or trout where its eggs are laid, subsequently hatched, and fry emerge.

Refill - The coordinated hydro system is considered full, for the purposes of the IDU EIS modeling, when the amount of water stored in reservoirs is equal to 94 percent of the total available space.

Regional - Referring to the characteristics of an area, as opposed to those of a surrounding or adjacent area. Generally used in this EIS to distinguish between the Pacific Northwest and Canada or California or the Inland Southwest. (see Extraregional)

Relative - Considered in relation to a base case condition; comparative; not absolute or independent (opposed to absolute).

Relative change in survival - The difference in survival between the two alternatives divided by the base case survival value. The change in survival in relation to the base case survival.

Reliability - In a network power system, the ability of the system to continue operation while some lines or generators are out of service or while the system is under stress. BPA has established minimum standards in the Reliability Criteria and Standards. For distribution utilities, reliability is normally defined in terms of yearly cumulative outage times per customer, number of outages per year per customer, and revenue loss due to outages. (See REA, EPRI, or other published criteria.)

Relic collecting - The seeking out and removal of artifacts or other cultural resources by private persons. The practice consequently excludes opportunities for study or preservation of the site, and often results in destruction of artifacts, the site itself, and/or nearby sites.

Renewable resources - Resources for energy which are continually replenished. Water, for instance, is a renewable resource, while coal which is converted into carbon dioxide, water, and ash when burned is not.

Replication - A copy or reproduction of a cultural artifact. Replication is most often done for rock art or engravings, by making a mold or cast of the work.

Reserve margins - For a power plant or transmission facility, extra capacity above the amount projected to be needed, to allow for unanticipated demand for power, equipment failure, or other unforeseen events.

Reservoir draft rate - The rate at which water, released from storage behind a dam, reduces the pool elevation of the reservoir.

Reservoir elevations - The various levels reached by water stored behind a dam.

Resident fish - Fish species which reside in fresh water during their entire life cycle.

Residential Exchange Program - An exchange of power prescribed by section 5(c) of the Pacific Northwest Power Act. Pacific Northwest utilities sell BPA an amount of power equal to their residential and small farm load, in exchange for less-expensive Federal electricity. The cost benefits are directly passed on by the utilities to their residential and small farm consumers, in the form of lower retail rates to those customers.

Residual fuel oil - Fuel oil that remains after separation of valuable distillates (such as gasoline) from petroleum through distillation.

Resource mix - The different types of resources used to generate power (e.g., hydroelectric, thermal, etc.) within a given area or for a given utility.

Resource schedule - The planned schedule of when and what resources will be available in the future to serve load in a given area or of a given utility.

Retrofit - To weatherize an existing structure.

Riprap - Broken rock, cobbles, or boulders placed on the bank of a stream or river for protection against the erosive action of water.

Run-of-river plant - A hydroelectric plant with little or no ability to regulate flow. These plants operate based only on available streamflow and some short-term storage (hourly, daily, or weekly). Run-of-river dams do not have sufficient storage to enable them to shape energy production among seasons.

Salmonids - Fish belonging to the family of salmonidae, including salmon, trout char, whitefish, and allied freshwater and anadromous fish.

Scoping - The definition of the range of issues requiring examination in studying the environmental effects of a proposed action. Scoping generally takes place through public consultation with interested individuals and groups, as well as with agencies with jurisdictions over parts of the project area or resources in that area. Scoping is mandated by the Council on Environmental Quality regulations.

Seasonal storage - In the utility power sales contract, the ability to store water in reservoirs and to thereby change the planned or actual energy generation at hydroelectric facilities in one month and to compensate for such change in another month, either using a customer's own facilities or the facilities of others which the customer has a contractual right to use.

Secondary revenues - Revenues received from sales of secondary energy, which is the energy produced in excess of firm power due to favorable water conditions.

Secondary sales - Surplus power, both firm and nonfirm, in the Pacific Northwest that is available for sale to the Pacific Southwest.

Sedimentation - The settling of material (such as dust or other particles) into water and eventual deposition on the bottoms of streams, rivers, and so on.

Settling ponds - A pond into which water containing suspended solid material is discharged to allow the solid material to separate from the water by gravity.

Shaping - The scheduling and operation of generating resources to meet load of changing levels. Load shaping on a hydro system usually involves the adjustment of storage releases so that generation and load are continuously in balance.

Simulation - The representation of an actual system by analogous characteristics of some device easier to construct, modify, or understand, or by mathematical equations.

Slag - In the context of this EIS, molten or solidified ash formed from noncombustible material in a fuel by chemical action and fusion at boiler operating temperatures.

Sludge - The wet, solid or semisolid material formed when particulate air pollutants and/or sulfur dioxide is removed by a wet scrubber air pollution control device.

Slurry pipeline - A means of coal transport in which the coal is finely ground, mixed with water, and run through a pipeline to its destination, where it is dewatered and combusted.

Small hydro - Generating resources which use running water to generate electric energy, but which are small in generating capacity. BPA generally considers small hydro projects to be those capable of producing 25 average MW or less.

Smolt - A juvenile salmon or steelhead that is migrating to the ocean and is in a physiological state to transition from fresh to salt water.

Snowmelt freshet - Increased streamflow from the melting of accumulated snowfall.

Spawning - The act of fish releasing and fertilizing eggs.

Spill (forced) - Water for which there is not storage capability in the system reservoirs and which could not be used for power production because the resulting flows would exceed turbine capacity.

Spill (inadvertent/overgeneration) - An amount of water which could have been used to generate electricity but was not because of lack of available market, and inability to store for later use.

Spill (programmed or planned) - Water intentionally passed through a hydroelectric project without producing electricity. This is usually done for fisheries mitigation proposes.

Spill Plan - A plan to provide a certain percentage of the total flow of a project as spill, for Federal and non-Federal projects.

Spoil piles - Heaps of soil and other material removed during surface mining, and later used to reclaim the site.

Sport fish - Fish which are sought by recreational fishermen.

Spot market - A market for electricity characterized by negotiation almost solely on the basis of price, for relatively short-term sales.

Storage reservoir - A reservoir in which storage is held over from the annual high-water season to the following low-water season. Storage reservoirs which refill at the end of each annual high-water season are "annual storage" reservoirs. Those which cannot refill all usable power storage by the end of each annual high-water season are "cyclic storage" reservoirs.

Stratification (chemical) - The separation into layers differentiated by chemical composition.

Stratification (thermal) - The separation into layers differentiated by temperature.

Subalpine - A terrestrial zone of high upland slopes, immediately below the timberline, characterized by conifer forest consisting of spruce and fir.

Subyearling - A juvenile salmonid, normally a fall or summer chinook salmon, that hatches and migrates to the ocean in the same year.

Surplus energy - Generally energy generated that is beyond the immediate needs of the producing system. Specifically for BPA, firm or nonfirm electric energy generated at Federal hydroelectric projects which would otherwise be wasted if there was not a market for the energy.

Surplus firm energy - Energy that can be generated and guaranteed to be provided, but is excess to demand.

Surplus firm power - Power that can be provided on a guaranteed basis, that is excess to system demand, and that can be provided in an agreed upon shape.

Surplus nonfirm energy - An excess of interruptible energy that is available due to water conditions better than critical.

Surplus peaking capacity - Electric peaking capacity for which there is no demand in the Pacific Northwest at the rate established for the disposition of such capacity.

System Stock Survival - The survival of migrating juvenile salmon or steelhead of a particular fish stock from the point of entry into the hydroelectric system to a point below Bonneville Dam.

Tailwater - The water surface immediately downstream from a dam or hydroelectric power plant.

Thermal resources - Generating plants which convert heat energy into electric energy. Coal, oil, and gas-fired power plants and nuclear power plants are common thermal resources.

Thermal structure - Reservoirs stratify into three layers in summer months: light warmer water on surface, a thermocline of cooler water, and a layer of cold oxygen deficient water on bottom. Rapid drawdowns cause this stratification to breakdown, reducing production of food organisms, and cooling water temperatures.

Total suspended particulates - An air pollution term referring to all matter contained in a sample of air which is in solid or liquid form regardless of its particle size or chemical composition.

Trace elements - Pollutants, often metals in ionic or chemically combined form, which appear in very small concentrations in water, or in reference to air pollution, which constitute a very small part of the total amount of particulate pollution by weight.

Transmission grid - An interconnected system of electrical transmission lines and associated equipment for the transfer of electric energy in bulk between points of supply and points of demand.

Transmission losses - Power lost in transmission between one point and another.

Turbidity - A measure of the optical clarity of water, which depends on the light scattering and absorption characteristics of both suspended and dissolved material in the water.

Turbine capacity - The maximum amount of water that can be passed through the turbines of the dam at any instant.

Utility retail rates - The prices for electricity that a utility charges its classes of consumers.

Variable costs - The costs that are incurred or are increased when a power plant operates.

Variable ECC - An update of the January through July portion of the ECC. It is based on expected amount of spring runoff with available forecasts.

Variable Industrial Power Rate - The adjustable rate under which the aluminum DSIs currently buy power from BPA.

Venting - The release of limited amounts of gases or vapors to maintain pressures within tanks, pipes, and other equipment involved in oil and natural gas processing and transportation within design limits.

Water Budget - A part of the Pacific Northwest Power Planning Council's Fish and Wildlife Program calling for a volume of water to be reserved on a planning basis and released when and if needed to augment stream flows in order to assist in the downstream migration of juvenile salmon and steelhead. The Water Budget shapes flows from April 15 through June 15 using a volume of water specified by the Regional Council.

Water conditions - The overall supply of water to operate the Pacific Northwest hydroelectric generating system at any given time, taking into account reservoir levels, snowpack, needs to provide water or retain water to meet various operating constraints (such as the Water Budget, flood control, flow constraints, etc.), weather conditions, and other factors.

Wheeling - The use of the transmission and distribution facilities of one system to transmit power of and for another system.

Wheel turning load - [see Appendix B]

Wholesale rates - The prices for electricity that a utility charges for power that will be resold. In BPA's case, BPA also charges wholesale rates to its DSI customers because they buy at relatively high voltage.

Yearlings - Juvenile salmon and steelhead that migrate to the ocean, often spending a full year rearing in fresh water.

Zooplankton - Aquatic animals which cannot actively swim against the current and which cannot make their own food by photosynthesis.

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