Non-Federal Participation In Ac Intertie Final Environmental Impact Statement

Volume 1: Environmental Analysis

Bonneville POWER ADMINISTRATION	DOE/eis-0145 January 1994

Non-Federal Participation in AC Intertie
Final Environmental Impact Statement
(DOE/EIS - 0145)

Responsible Agency: U.S. Department of Energy, Bonneville Power Administration (BPA)
Title of Proposed Action: Non-Federal Participation in AC Intertie
States and Other Areas Involved: Washington, Oregon, Idaho, Montana, California, Nevada, Utah, New Mexico, Arizona, Wyoming, British Columbia

Abstract: BPA is considering action in two areas: (1) non-Federal access to the AC Intertie, and, (2) BPA Intertie marketing. BPA's preferred alternative for non-Federal access is the Capacity Ownership alternative combined with the Increased Assured Delivery--Access for Non-Scheduling Utilities alternative; the preferred alternative for BPA Intertie marketing is the Federal Marketing and Joint Ventures alternative. BPA considered these two areas previously in its Intertie Development and Use eis of April 1988. The eis resulted in BPA decisions to participate in the construction of the Third AC Intertie, to allow non-Federal access to BPA's share of the Pacific Northwest-Pacific Southwest (PNW-PSW) Intertie (AC and DC lines) pursuant to a Long-Term Intertie Access Policy (LTIAP), and to pursue BPA's export marketing alternative. The decision on allowing direct financial non-Federal participation in the Third AC line was deferred to a later, separate process, examined here. Also, BPA's export marketing objectives must now be examined in view of changed operations of Columbia River hydro facilities for improved fish survival.

In the No Action alternative, non-Federal access is allowed only pursuant to the May 1988 LTIAP and no new long-term BPA or joint venture contracts with California parties are assumed. Different means of providing non-Federal access are contained in the following alternatives: Capacity Ownership (non-facility specific capacity ownership up to 725 MW), Capacity Ownership with Limited PSW Access (a scenario in which PSW parties in the Third AC have limited access arrangements in California), Increased Assured Delivery (non-Federal access to additional MWs but controlled by provisions of the LTIAP), Increased Assured Delivery With Intertie Access for Non-Scheduling Utilities (direct LTIAP access is expanded to entities which now must gain access through arrangements with BPA or other PNW scheduling utilities), and Economic Priority (Intertie access determined based on net economic benefit of proposed transactions). The No Action alternative with respect to BPA Intertie marketing includes existing BPA contracts with PSW parties and existing joint ventures. The Federal Marketing and Joint Venture alternative (preferred BPA Intertie marketing alternative) contains a BPA marketing proposal designed to increase the value of hydro flows provided for fish. The alternative would include potential BPA bilateral contracts with California parties and joint ventures involving other PNW parties.

BPA's preferred alternatives are Capacity Ownership combined with Increased Assured Delivery With Intertie Access for Non-Scheduling Utilities, and Federal Marketing and Joint Ventures.

The Draft eis was mailed to over 1,500 agencies, groups and individuals. (See Chapter 7.) Public comments were received during a 45-day comment period, during which a public meeting was held in Portland on September 21, 1993. The Final eis includes the public comments and responses.

To request copies of the eis please contact:
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CHAPTER 1 PURPOSE AND NEED 1

1.1 Need

Bonneville Power Administration (BPA) and other Pacific Northwest (PNW) entities need interregional transfers with the Pacific Southwest (PSW) region using the PNW-PSW Intertie.

1.2 Purposes

The means of providing interregional transfers must serve the following purposes:

1. Provide fair Intertie access to non-Federal parties;
2. Support BPA's obligation to assure recovery of the costs of the Federal Columbia River power and transmission systems;
3. Support acceptable environmental quality;
4. Benefit overall economic and operational efficiency of the PNW and PSW systems connected by the Intertie.

1.3 Relationship to Other Actions

1.3.1 Federal Columbia River Operations

System Operation Review (SOR). BPA, the U.S. Army Corps of Engineers (COE), and the U.S. Bureau of Reclamation are jointly conducting the SOR process, which is a public review of the multi-purpose operation of Federal hydro facilities in the Columbia River Basin. A Final Environmental Impact Statement (eis) is planned for 1994. The SOR process will determine the operating requirements necessary to serve the multiple purposes of the Federal facilities, including power generation, fisheries, recreation, irrigation, navigation, and flood control. The resulting decisions on operating requirements will apply to power operations for Intertie transactions and all other BPA power transactions. The proposals studied in this Non-Federal Participation (NFP) eis do not supplant the SOR decision process. BPA will serve its contractual obligations with its mix of resources consistent with the operating constraints applicable to each resource.

1992 Columbia River Salmon Flow Measures Options Analysis/eis (Flows eis) and the Interim Columbia and Snake Rivers Flow Improvement Measures for Salmon Supplemental Environmental Impact Statement of March 1993 (1993 Flow Seis). BPA cooperated with the COE in these eiss, which analyzed alternate annual hydro operating plans for periods prior to the completion of the SOR process. Biological assessments have been prepared addressing effects on potential endangered or threatened species.

1.3.2 Endangered Species Act Processes

The National Marine Fisheries Service is currently acting on petitions to protect certain anadromous fish species in the Columbia and Snake River systems. Operating requirements for Federal hydroelectric facilities within these river systems will be subject to decisions made under these processes. The proposals studied in the NFP eis do not supplant Endangered Species Act (ESA) recovery plan processes. The NFP eis analysis uses the best available information regarding operations relevant to fisheries and other uses.

1.3.3 BPA Resource Programs eis

BPA's Resource Program establishes a long-term strategy and budget plan for development of conservation and other resources. BPA has prepared a Resource Programs eis

(DOE/eis-0162, February 1993) which is intended to provide information for use in BPA's Resource Program processes. The Resource Programs eis looks at the effects of generalized resource acquisition strategies on resource acquisition and operation. Because the Resource Programs eis identifies and analyzes implications of BPA and non-BPA PNW resources, certain portions will be incorporated here by reference. This eis analysis is consistent with the assumptions used in the 1992 BPA Resource Program. Some BPA resource acquisitions are subject to further site-specific environmental processes. Conservation is covered by the Resource Programs eis for residential, commercial, industrial, and agricultural sectors. Generation resource acquisition will be subject to further site-specific review.

1.3.4 Background on Third AC Intertie Decision Processes

In June 1987, several members of Congress asked BPA to give full consideration to non-Federal participation in the financing and use of the Third AC Intertie expansion. This expansion was expected to accomplish three major objectives:

- first, to provide an additional market for surplus BPA power to enable BPA to increase its revenues and thereby help BPA repay the U.S. Treasury in a timely manner;
- second, to serve loads in the PNW and PSW more economically by taking advantage of diversity of load patterns and resource types between the two regions; and
- third, to provide surplus PNW energy, when available, to displace higher-cost PSW generation. (Non-Federal Participation Study, March 1988.)

Also, utilities were interested in gaining transmission access under more flexible terms and for longer than the 20-year maximum terms allowable under the Long-Term Intertie Access Policy (LTIAP) to benefit from the greater value of longer-term commitments.

In April 1988, BPA published the Intertie Development and Use (IDU) eis. This eis studied the environmental and economic effects of the use of the Intertie, including the Third AC Intertie. AC Intertie capacity after addition of the Third AC is expected to be approximately 4,800 megawatts (MW). Including the Third AC, total Federal and non-Federal Intertie capacity will be approximately 7,900 MW -- 4,800 MW on the two AC lines and 3,100 MW on the DC lines. BPA's September 1988 Record of Decision explained the decision to proceed with the Third AC construction project. At that time, BPA's decision on requests for non-Federal ownership access to the added capacity was deferred to the NFP eis process.

The NFP eis will lead to a decision on inclusion of non-Federal parties in the funding and use of the added transmission capacity. The Third AC Intertie will be a part of the Pacific Northwest-Southwest Intertie, authorized by Congress. BPA, Portland General Electric (PGE), and PacifiCorp each own portions of the facilities north of the Oregon-California border comprising the PNW-PSW Intertie. Ownership of the existing PSW portion is divided among private and public utilities and the Western Area Power Administration.

The southern portion of the Third AC Intertie is called the California-Oregon Transmission Project (COTP). The COTP resulted from a July 1984 congressional authorization that directed the Secretary of Energy to participate with non-Federal entities in developing the COTP. Participants in the COTP are listed in Appendix G, Part 2.

1.3.5 BPA Long-Term Intertie Access Policy

BPA has provided access to its existing AC and direct current (DC) Intertie capacity under the provisions of the May 17, 1988, Long-Term Intertie Access Policy (LTIAP).

1.3.6 BPA Rates and Ratemaking Processes

BPA ratemaking procedures are principally governed by the Northwest Power Act. BPA rates must be consistent with this and other laws and administrative regulations. The price to be paid by non-Federal participants in the Intertie will be set pursuant to a formal ratemaking process.
The rate for non-Federal participation is considered to be a part of the Capacity Ownership proposal and has no separate environmental implications. This analysis will use the latest available information on BPA's current and projected wholesale power and transmission rates.

1.3.7 The Northwest Power Planning Council's Regional Energy Plan and Fish and Wildlife Program

The Northwest Power Planning Council's (Council) Energy Plan (Plan) and the Fish and Wildlife Program (Program) are the results of separate public processes conducted by the Council. The NFP eis analysis will use the best available information on matters relevant to the Energy Plan and Fish and Wildlife Program.

1.3.8 Bellingham Area Reinforcement eis -- Northern Intertie With Canada

BPA has begun this eis process to examine the effects of adding transmission facilities to increase the capacity of the Northern Intertie with Canada. The Bellingham eis will also look at the effects on the power system of power contracts that may use the Northern Intertie. The NFP eis does not examine different potential transactions with Canada, but, depending on the outcome of future processes, some of the generic Southern Intertie contracts examined in the NFP eis could include power deliveries from Canada.

1.3.9 Energy Policy Act of 1992

Recent amendments to the Federal Power Act, as contained in Title VII of the Energy Policy Act of 1992 Section 721 give the Federal Energy Regulatory Commission (FERC) new authority to order transmission access to be provided to requesting entities by entities, including BPA, that own transmission lines.

1.3.10 BPA Protected Areas Policy Development

In 1988, the Council approved amendments to its Program and Plan that defined Protected Areas. Protected Areas represent the region's most valuable fish and wildlife habitat, and the Council desired to protect such areas from new hydropower development. To comply with the Council's Program and Plan, in 1988, BPA adopted as part of its LTIAP provisions that would decrease utilities' access to the Intertie if they develop or acquire the output from a new hydro project located in a Protected Area in the Columbia River Basin.

In 1992, in the Administrator's Record of Decision for the Final eis on the Initial Northwest Power Act Power Sales Contracts, BPA stated that it would "undertake a policy development process to establish a consistent BPA policy for enforcement of the [Council's Protected Areas] Rule." That policy development is underway. See Appendix G for further detail on Protected Areas. BPA's current intent is that its policy would apply to BPA practices including wheeling, resource acquisitions, and billing credits for resources within the Columbia River Basin. The Resource Programs eis Record of Decision states that BPA will not acquire resources in Protected Areas.

Non-Federal participation in the Third AC Intertie will be consistent with LTIAP provisions regarding Protected Areas and with BPA's new Protected Areas policy if such a policy is adopted prior to execution of Capacity Ownership agreements.

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CHAPTER 2 AFFECTED ENVIRONMENT 1

2.1 Study Area

The study area includes the States of Idaho, Oregon, and Washington; the State of Montana west of the Continental Divide; and portions of the States of Wyoming, Utah, Nevada, Arizona, New Mexico, and California. It also includes the Canadian Province of British Columbia.
Appendix G contains supplemental data on the topics covered in this chapter.

2.2 Existing Power Systems

Pacific Northwest

Hydropower produces about two-thirds of the total electricity used by the PNW. There are 58 major non-Federal hydroelectric dams with a combined nameplate rating of over 27,800 MW. There are 31 federally owned dams with a total nameplate rating of 19,552.5 MW. See Figure 2-1, page 2-2. (Also, see Appendix G, Table G-1, and BPA's 1992 PNW Loads and Resources Study.) The amount of streamflow varies from month to month and from year to year according to weather and other natural conditions. In normal or better years of precipitation and run-off, water is readily available to produce electricity needed in the PNW. When precipitation, runoff, and streamflow are down, additional water is released to maintain required flows. In an average year, 16,400 average megawatts (aMW) of hydropower are produced. In a critical period, the period of lowest flow, the hydro system produces about 12,400 aMW. In the United States, major Federal storage reservoirs exist behind Libby, Grand Coulee, Albeni Falls, Hungry Horse, and Dworshak Dams. Three Canadian dams (Mica, Keenleyside, and Duncan) also provide substantial water storage for the Columbia River Basin.

The amount of run-off in the system is highly variable. The average annual run-off is about 165 cubic kilometers (km3) (134 million acre-feet (MAF)), but it has varied from about 96 km3 (78 MAF) to 238 km3 (193 MAF). The monthly mean natural streamflow at The Dalles, Oregon, ranges from 1,133 cubic meters per second (m3/sec) (40,000 cubic feet per second (cfs)) in winter to 16,992 m3/sec (600,000 cfs) in the spring.

The total storage capacity of the Columbia River system is about 52 km3 (42 MAF), or less than a third of average run-off. Half of that storage capacity is in Canada. The Canadian portion of the storage is operated by British Columbia Hydro and Power Authority (BC Hydro). The PNW and BC Hydro coordinate operation of the hydro system to increase operational flexibility and to enhance power production.

Figure (page2-2 Major Dams in the Pacific Northwest)

Figure 2-1

Coordination of the PNW and BC Hydro systems began in 1964 with the ratification of the Columbia River Treaty (Treaty). The Administrator of BPA (U.S. Department of Energy) and the Division Engineer, North Pacific Division, COE (U.S. Department of the Army) are the designated U.S. Entity for the Treaty. The Canadian Entity is BC Hydro. Under the Treaty, Canada constructed three storage dams in British Columbia. The Treaty provides that the total Canadian storage at Mica and Keenleyside, on the Columbia River, and Duncan, on the Kootenay River, is 19 km3 (15.5 MAF). The United States was allowed to construct 6 km3 (5 MAF) of storage at Libby Dam on the Kootenai [Kootenay in Canada] River.

The three Canadian storage dams and Libby enabled downstream U.S. projects to produce up to an additional 2,800 MW of dependable capacity. One-half of these "downstream benefits" belongs to Canada.

BC Hydro also built storage on the Columbia River system in excess of that required by the Treaty. This non-Treaty storage includes Revelstoke Dam and an additional 6 km3 (5 MAF) of usable storage at Mica. BC Hydro and BPA have signed a Non-Treaty Storage Agreement for use of this additional storage.

PNW thermal resources are primarily owned by utilities other than BPA. See Figure 2-2, page 2-5. (Also see Appendix G, Table G-2.)

The PNW resource mix also includes energy conservation. The 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 broad end-use categories (residential, commercial, industrial, and agricultural sectors). By improving end-use efficiency, energy conservation offers a means of regulating load growth and offsetting the need for new generating resources. Other PNW entities also pursue conservation, sometimes with BPA funding.

California and the Inland Southwest

The California resource base is diverse. Over the last decade, California utilities have all but ceased use of oil fuel by converting to natural gas and by diversifying their in-state resource base to include nuclear power units and alternative fuel resources such as hydro, geothermal, wind, biomass, and solar. In addition, California utilities have increased imports of their shares of out-of-state coal-fired resources, purchases from utilities in the PNW and Inland Southwest (ISW), and generation from non-utility energy producers (independent power producers, and qualifying facilities (QFs)).

Estimates from the California Energy Commission's (CEC) 1992 Draft Final Electricity Report (ER 92) show that in 1992 nuclear power contributed 5,752 MW of dependable capacity. Gas-fired resources add 22,503 MW plus 2,268 MW of reserves. Out-of-state coal resources owned by California utilities contribute 3,756 MW. QF resources currently provide 8,211 MW of dependable capacity. Figure 2-3, page 2-6, shows California's existing resource mix by type. Appendix G, Part 2, contains tables showing dependable capacity available from existing resources for each major California utility.

In addition, the PNW in 1992 provided California parties 2,548 MW of firm purchases. Regarding PNW nonfirm energy, ER 92 assumes that up to 27,000 gigawatt hours (gWh) or about 3,000 aMW are available. Through 1997, California utilities will purchase 2,751 MW of firm power and as much as 22,000 gWh, or 2,511 aMW, of economy energy from ISW utilities.

The peak load demands of the PNW and California occur at different times. The PNW peak demands occur in winter, and California's peak demands occur in summer. During the summer, the hydro-based PNW and BPA systems tend to have excess capacity, which can be used to help meet California's summer peak demands. California's thermal-based system tends to have excess capacity in the winter, which can help the PNW meet its winter peaks. Full use of both systems can reduce the need for new resources in each system. BPA currently has several seasonal energy and capacity/energy exchange contracts in effect with a number of California utilities.

The ISW resource mix includes hydro, coal, gas, oil, and nuclear generation. Coal provides about 58 percent of the region's generating capacity. Oil- and gas-fired generation account for about 26 percent, hydropower produces approximately 17 percent, and the Palo Verde (Arizona) nuclear plants #1 and #2 account for 9.3 percent of the region's installed capacity. As much as 3,600 MW of the ISW's total capacity could be available on a firm basis to supply export power to California and other areas in the summertime (Western Systems Coordinating Council, April 1991).

Figure (Page2-5 THERMAL POWER PLANTS...)

Figure 2-2

Figure (Page2-6 California Statewide...)

Figure 2-3

British Columbia

Hydroelectric generation accounts for 95 percent of all electricity production in British

Columbia. BC Hydro, a provincial crown corporation, generates, transmits, and distributes electricity.

The only major thermal plant is a gas/oil plant on Burrard Inlet in Vancouver, BC. The Burrard thermal project is capable of producing up to 912 MW of capacity and 630 aMW of energy. In the past, the dependable capacity has been much less because there were no winter peak gas supplies. The plant capacity was restricted to 0 MW in the winter, with 370 aMW of energy. However, in recent years, natural gas has been purchased at competitive prices on the spot market, increasing the contribution of Burrard to 40 MW of dependable capacity and 600 aMW of energy.

2.3 Regulatory and Planning Environment

2.3.1 PNW Regulatory And Planning Processes

BPA's Resource Program Process

Every two years, BPA conducts a public process to plan for the power needs of its customers. The result is a plan -- the Resource Program -- that outlines actions BPA will take to meet energy needs for up to a decade. Based on a range of load forecasts developed jointly by BPA and the Council, the Resource Program identifies the amounts and types of resources to acquire and their expected cost. The Resource Program is the vehicle BPA uses to describe its activities implementing the Council's Conservation and Electric Power Plan. BPA has prepared a Resource Programs eis that provides environmental information for BPA's Resource Programs. BPA resource acquisition decisions are made subsequent to the Resource Program. Although conservation resources are covered by the Resource Programs eis, specific generation resource acquisitions are subject to site-specific environmental reviews tiered to BPA's Resource Programs eis.

Northwest Power Planning Council

Pursuant to the Northwest Power Act, the Council develops a Northwest Conservation and Electric Power Plan (Plan), including a Fish and Wildlife Program (Program). The Plan and Program serve as guidance to BPA in its Resource Program process and in BPA's actions with respect to fish and wildlife. The Council's Plan is not binding with respect to the resource decisions of other PNW utilities, but serves as resource planning and policy guidance for PNW utilities and state agencies involved in utility regulation.

BPA Acquisition of Major Resources

Section 6(c) of the Northwest Power Act provides that BPA proposals to acquire major resources be reviewed for consistency with the Council's Plan. A major resource is one that has a planned capability greater than 50 aMW and is acquired for more than 5 years. BPA and the

Council recently concluded a public process on their respective policies for establishing complementary decisionmaking processes for evaluating such BPA proposals.

PNW States Electric Utility Regulation

Each PNW state regulates Investor Owned Utilities (IOUs) to the extent they operate a service area in the state. Some IOUs are subject to regulation by two or more states. Utilities that are municipals, cooperatives, or other publicly owned entities are not subject to these state regulatory agencies; however, the siting of specific resources would be subject to appropriate state (and sometimes Federal) approvals. The State of Washington applies a least-cost planning principle in its regulation of subject utilities, and the State of Oregon is beginning to do so.

2.3.2 California Regulatory and Planning Processes

California Energy Commission and California Public Utilities Commission

The California Energy Commission (CEC) determines if additional resources are needed, the timing of these resources, and preferred resource attributes in its biennial resource planning Electricity Report (ER) document. The ER process applies to both municipal utilities and California's three IOUs. The intent of the ER process is to provide planning guidance for those municipal utilities pursuing acquisition of new resources through requests for proposals (RFP) and to guide the California Public Utilities Commission (CPUC) as it oversees the IOUs' acquisition of new resources through the CPUC's Public Utilities Regulatory Policies Act QF bidding program. If a municipal utility's proposed resource acquisition follows the resource recommendations set forth in the ER document, the CEC is allowed to expedite the need determination in siting cases and the issuance of required certifications. Concurrently, the IOUs

use the ER recommendations in preparation of their resource plan submittals before the CPUC.
The ER serves as a basis for the CPUC to authorize the IOUs' supply-side additions in its Biennial Resource Plan Update (BRPU) process. The BRPU ultimately determines the amount, timing, and size of a resource bid solicitation. Currently, the BRPU resource program for IOUs is limited to QFs. The municipal utilities' RFP system invites proposals from all sources. In the current CPUC bidding process, no other resource sponsors, including the utility itself, may compete directly with QFs.

In addition, California air quality regulation plays a large role in electric power resource planning. It is discussed in Section 2.5.1, page 2-14.

2.4 Demand for Power: Future Resources and Contracts

2.4.1 Pacific Northwest

Electric loads within the PNW 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 winter for heating. In some areas east of the Cascades, the

difference between winter and summer loads is less pronounced: summertime irrigation and air conditioning loads can approach or exceed winter heating demand.

Industrial users account for roughly 40 percent of electric consumption, commercial users for 20 percent, and residential users for over 30 percent. The region's hydro-based power historically has been much less expensive than power from fossil fuels, which are used more in other regions. As a result, residential customers in the region use twice as much electricity for space and water heating, at half the national average cost per kilowatt-hour.

Slightly less than half of PNW loads are served by BPA, which markets power from COE and Bureau of Reclamation dams and the Washington Public Power Supply System Nuclear Plant No. 2. The public utilities and IOUs sell their own generated power or power from BPA to regional end-use consumers (those who use and do not re-sell the power). BPA's authority stipulates that it serve all requested needs within the region first, and that it supply power to public utilities and cooperatives before IOUs. Only if more power is available than is needed by the region can it be sold and transmitted outside the region.

Demand forecasts in the 1970s anticipated an energy shortage. New generating resources were planned and built into the early 1980s. When demand for electricity did not increase as expected, the construction of the additional large-scale generating facilities slowed considerably. By 1990, regional demand had almost balanced regional supply. It is not certain whether or not this balanced condition will continue, because there are wide variations in forecasted loads. Under BPA's low and medium-low forecasts, the region could experience surplus conditions for 10 to 20 years. However, under the medium, medium-high, and high forecasts, the region would experience deficit conditions throughout the 20-year study period. (See Figure 2-5, page 2-11.)

PNW resources available to meet future demand for power are shown in Appendix G, tables G-3 and G-4, taken from BPA's Resource Programs eis. Table G-3 shows BPA's future resource stack (column 2, "Base Case Resource Stack"). This list of resources includes cost-effective conservation as the highest priority resource, renewable resources and cogeneration, the WNP 1 and 3 nuclear generating projects (Note: these plants may be terminated), and some fossil fuel options, such as gas-fired combustion turbines and coal plants. BPA's Base Case resource stack was developed beginning with an economic comparison among resources and then adjusting for environmental costs and benefits. Table G-4 shows an assumed resource stack for PNW IOUs. The types of resources are similar to BPA's but the adjustment for environmental costs and benefits was not applied.

2.4.2 California and the Inland Southwest

State-wide peaking electricity demand in California in 1992 was 62,115 MW. Roughly 90 percent of this demand was from three IOUs and the two largest municipally owned utilities. Available capacity resources in 1992 totaled 65,163 MW.

California utilities' future resource needs are expected to increase due to a growing population and an expanding California economy. From 1991 through 2011, the statewide annual peak demand is forecasted to grow at an annual rate of 2.4 percent. Statewide annual electricity use

is forecasted to grow at about 2.0 percent per year. Figure 2-5 shows California's long-range load/resource balance.

Recently, the CEC completed its ER 92 and published the Draft Final ER 92. The Draft Final ER 92 recommends a balanced set of resource options that includes cost-effective demand-side management (DSM) programs, gas-fired repowerings, efficient new gas plants, renewable resources, and cost-effective purchases from out-of-state that increase the efficient use of existing resources throughout the west. These options (described in more detail below) would meet the state's estimated need for 3,204 MW of new supply-side capacity by the year 2003.

ER 92 found that 78 percent of the capacity required to meet California's estimated 68,370 MW total load by 2003 exists or is already committed. Pending resources and PNW "spot capacity" purchases account for another 6 percent. Of the remaining 12,050 MW statewide resource need projected in ER 92, 8,846 MW will be met through demand-side management savings; 2,517 MW via resource additions by the IOUs; and 687 MW through acquisition by municipal utilities. Appendix G, Part 2, includes the CEC's ER 92 needs assessment of California's three IOUs and the larger municipal utilities.

Demand-Side Management. DSM programs are expected to be the biggest new resource in California's supply plans over the next decade. DSM programs avoid new generation, reduce energy costs, improve air quality, increase resource diversity, and conserve natural resources. By 2003, statewide savings and demand reductions are projected to be 8,846 MW of capacity and 23,514 gWh, or 2,684 aMW, of energy. The levels are expected to increase by the year 2011 to add another 5,064 MW in capacity savings and 15,147 gWh, or 1,729 aMW, in energy savings.

Repowering. A repowering involves replacing the existing boiler in an older, fossil-fuel steam plant with a combustion turbine and a heat recovery steam generator. The result is a combined cycle plant in which all of the capacity is efficient with a relatively lower emission rate. Additionally, the combined cycle plant is dispatchable to maximize flexibility. The repowered plant makes use of an existing site where the electricity system infrastructure is already in place. Not only does it replace an older, inefficient plant, but it can obviate the need to run other similar plants.

Figure 2-4
PNW Regional Firm Energy Surpluses/Deficits

Assuming No Resource Acquisitions
Figure (Page2-11 Figure 2-4...)

SOURCE: Bonneville Power Administration. 1990. Pacific Northwest Loads and Resources Study.
Bonneville Power Administration, Division of Resources, Portland, Oregon

Figure 2-5
Statewide Capacity Requirements and Existing,
Committed, and Pending Resources
Figure (Page2-11 Figure 2-5...)

New, Efficient Gas Resources. California's reliance on natural gas is expected to increase because: (1) gas-fired resources are cleaner than other thermal generation; (2) gas supplies are expected to be plentiful; and (3) forecasts of gas prices remain moderate over the long-term. In ER 92, the CEC states that the decline in natural gas price appears to make gas-fired plants the most cost-effective resource option available over the next 12-year forecast period.

Renewable Resources. California has led the Nation in development of renewable resources, and California regulators have stated that a diverse energy base for electricity generation is sound policy. However, because of lower gas prices, the costs of renewable resources currently do not compare favorably with fossil-fueled resources. Recognizing the environmental and diversity benefits of renewable resources, regulators "set aside" a portion of future resource requirements for renewable resources as a hedge against high fossil fuel prices and as a low-polluting alternative source of energy.

Shutdown of Nuclear Units. In 1988, the public owners of Sacramento Municipal Utility District (SMUD) voted to close the 918 MW Rancho Seco Nuclear Generating Station in Northern California. Then, in 1992, the CPUC and joint owners Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) agreed to the early closure of the 411 MW San Onofre Unit 1 in Southern California by August 1993. Both retirements are a result of required safety refurbishments. The refurbishments are considered more costly than other resource alternatives. These actions will lead to a more diversified resource supply plan to replace such capacity.

Geothermal. Since 1990 there has been a steady and significant decline in the output of the

Geyser geothermal steam field in northern California. As a result, the quantity and quality of geothermal steam at the Geysers has been derated and plans for new units abandoned. This results in a greater need for capacity in utility resource supply plans.

Out-of-State Purchases. During the last two decades, energy imports have made an important contribution to the diversity of California's electricity system. In addition to the AC and DC Interties with the PNW, California has transmission links with the ISW and Mexico of over 7,600 MW. At times, imports including generation owned in the Southwest by California's utilities have supplied enough energy to meet about one-third of California's electricity loads. In 1991, California utilities were under contract for about 5,100 MW of firm capacity from out-of-state suppliers. Nearly 54 percent of this firm capacity is from the Southwest states and Mexico. The remaining 46 percent is from the PNW. California utilities also purchase large amounts of nonfirm energy from both regions. In addition, California utilities own about 4,200 MW of coal-fired generation in the Southwest, which represents 18 percent of the region's total coal-fired generating capability.

Purchases from the PNW include short-term (nonfirm energy and short-term capacity) and long-term surplus (firm) arrangements such as power purchases or exchanges. Short-term purchases may last for a day or a period of months. ER 92 recognizes that PNW nonfirm energy is an important resource to California utilities and projects over the next 20 years that 27,000 gWh, or about 3,082 aMW, should be available to California utilities from the PNW.

California utilities make purchases referred to by them as "spot capacity," which may consist of on-peak PNW economy energy, as available, or short-term capacity purchases for which the energy is later returned. Spot capacity is a short-term capacity product that provides utility

system operational flexibility and serves peak load spikes, displacing expensive combustion turbines. Two types of contracts are used by California utilities: a reliability contract for summer capacity needs and a short-term summer purchase, exchange, or load factoring arrangement. These purchases normally displace high-cost resources and are more cost-effective than building new combustion turbines. Both California regulatory commissions recognize the value spot capacity provides and acknowledge that without this product, the need for new peaking resources would be accelerated by nearly 2 years. ER 92 assumes up to 1,900 MW of spot capacity is available to California from various sources for meeting California's short-term capacity needs.

Transmission Access. Municipal utilities within California and the Western Area Power Administration are owners of the COTP. COTP will carry approximately 1,600 MW of north-to-south transfer capability after its energization date in early 1993. Northern California owners of COTP will receive 88.3 percent, or 1,415 MW, with the remaining 11.6 percent, or 185 MW, owned by southern California municipals. Many of these utilities have negotiated or are negotiating long-term contracts with PNW parties. For example, BPA will provide Modesto-Santa Clara-Redding 100 MW after energization of the COTP. The Mead-Adelanto transmission line is being pursued to link California and the ISW. It will provide 1,200 MW of transmission capacity by the target on-line date of mid-1995.

New municipal contracts with IOUs increase transmission access. Most major public utilities in northern and southern California have or will soon have renegotiated interconnection contracts with the IOUs in whose service territories they exist. In general, all of these agreements tend to give the municipal utilities more transmission access to outside resources and markets in return for greater risk and responsibility for their own resource supply planning, acquisition, and operations. These contracts offer greater opportunity and flexibility for PNW transactions with these utilities. They also create more competition in the supply side of the market.

2.4.3 British Columbia

In British Columbia, load for Operating Year (OY) 1989-90 was approximately 5,066 aMW. Load growth is projected to average 3.0 percent per year through OY 2009-10 and 2.7 percent per year through OY 1999-2000. In the 1990s, conservation, improved system coordination, and resource efficiency gains are expected to help meet projected demand.

2.5 Natural Resources Issues

Information for this section was taken from:

U.S. Department of Energy, Bonneville Power Administration. 1993. Final Environmental

Impact Statement, Resource Programs, Vol. 1, pgs. 2-13 through 22 (DOE/eis-0162).
U.S. Department of Energy, Bonneville Power Administration. 1988. Final Environmental Impact Statement, Intertie Development and Use, Vol. 1, pgs. 3-20, 21, 23, and 32. (DOE/eis-0125-F).
State of California Energy Commission. 1993. Appendix F. Air Quality. State of California.

Information for state pollutant levels was taken primarily from the following sources:

Department of Health and Environmental Sciences. 1989. Montana Air Quality Data & Information Summary for 1987. Helena, Montana.
Department of Environmental Quality. 1990. 1989 Oregon Air Quality Annual Report. Portland, Oregon.
Washington State Department of Ecology. 1989. Washington State Air Monitoring Data for 1988. Olympia, Washington.

2.5.1 Survey of Air Quality Concerns

Pollutants of concern in this analysis are those produced by extracting, processing, transporting, and burning coal, oil, gas, or other fuels (e.g., waste wood) to produce electric power. Principal pollutants produced are the federally designated "criteria pollutants": sulfur dioxide (SO2), nitrogen oxides (NOx), particulates, hydrocarbons, ozone, carbon monoxide (CO), and lead. Of these, particulates, SO2, and nitrogen dioxide (NO2) are common emissions from electrical generation relying on combustion. Carbon dioxide (CO2), a major by-product of burning fossil fuels and other carbonaceous materials, may contribute to global climate change. Combustion generating plants may also emit heavy metals, radionuclides, and hazardous compounds. Generating technologies and their associated emissions are discussed in Appendix E. The detailed air quality information and data used in this analysis are also contained in Appendix E.

New thermal generating plants could be located in Oregon, Washington, California, Montana, the Inland Southwest, and British Columbia, Canada. Air quality is a concern in certain defined air basins and around certain existing generating plants in the study area. In these areas, more stringent controls are required for existing facilities, and any new major project must satisfy additional restrictions. Nonattainment areas have air pollution concentrations that do not comply with a portion of the National Ambient Air Quality Standards. Federal nonattainment areas in the study area are described below per type of pollutant. In addition, maps of California nonattainment areas are contained in Appendix G, pages G-16, 17, and 18. Federal air quality standards and those for Washington, Montana, Oregon, and Idaho are found in Appendix G. California air quality regulations are described below and in Appendix G, Part 2. California State and Federal air quality standards are found in Appendix G, Part 2.

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 Sierra Nevada mountains east of San Francisco, the San Francisco Air Basin, the Los Angeles Air Basin, southeastern Arizona, and central Colorado. The link between changing levels of generation and observable impacts of acid deposition is complex and difficult to quantify, depending on many variables such as microclimate, alkalinity of soil and water, and soil depth and composition.

Particulates

Particulates are fine, solid particles that remain dispersed in gases and stack emissions. Total suspended particulates (TSP) refers to all particles found in the air and includes pollutants from sources such as automobiles, agriculture, dirt roads, factories, and power plants. Particulates have impacts on health and affect visibility. A study of the impact of haze on visibility in the PNW found that, in the summer of 1984, 15 regional haze events occurred (Core et al. 1987). Power plants were not listed as sources.

Portions of Arizona, Nevada, Oregon, Washington, Idaho, Montana, Wyoming, Utah, and California are currently listed as nonattainment areas (Clean Air Act Amendments, 1990). Colstrip, in Montana, was designated as a nonattainment area for TSP in 1978, but is no longer designated as such.

Sulfur Dioxide

Sulfur compounds are key in the formation of smog and acid rain. In Washington and Oregon, SO_2 is typically not a problem. Burning of high-sulfur coal is not permitted in Oregon. There have been no recent standards violations, according to 1989 air quality reports for these states.
Portions of Nevada, Arizona, Montana, and Utah are in nonattainment for SO_2. Montana has had standards violations in the Laurel-Billings and Anaconda areas. The Laurel-Billings violation was traced to an oil refinery. The Anaconda emissions came from a now-closed copper smelter.

Nitrogen Dioxide

Nitrogen dioxide and nitric oxide (NO) are both called oxides of nitrogen (NO_x). Nitric oxide is formed in auto exhaust and most industrial combustion processes. In the presence of ozone, nitric oxide rapidly reacts to form nitrogen dioxide (NO_2). NO_2 forms during combustion.

No NO_x violations were reported by Oregon, Washington, or Montana in their 1989 air quality reports. The South Coast Air Basin in California is in nonattainment.

Carbon Monoxide

Carbon monoxide (CO), a colorless, odorless gas, is the product of incomplete combustion when natural gas, oil, wood, coal, or other materials are burned. CO increases when there is an inadequate supply of combustion air. The best means of controlling CO emissions is a properly designed and operated combustion process.

Automobiles are a primary source of CO. Thus, nonattainment areas tend to be in business districts and intersections where automobile traffic is heavy. These areas are located in the major population centers of each state in the study area.

Atmospheric Ozone

Ozone is a pungent, toxic, highly reactive form of oxygen. Ozone is not emitted directly to the air. It forms through a series of photochemical reactions that involve sunshine, other pollutants--most notably nitrogen oxides and volatile organic compounds (hydrocarbons)--and oxygen.

Ozone concentrations are related to volatile organic emissions from automobile exhausts and nitrogen oxides from other sources, and the amount of sunshine available. Thus, areas violating the standard tend to be in cities with high automobile use and abundant sunshine. In 1989, Washington reported one 1-hour violation in the Puget Sound area. Over the last decade, Portland, Oregon, has violated the standard several times. In Oregon, 1989 ozone levels were less than those reported earlier in the 1980s. This reduction is attributed to significantly cooler-than-average summer weather in that year. Portions of Oregon, Washington, California, and Arizona are listed as nonattainment areas.

Carbon Dioxide and Other Greenhouse Gases

Although not listed as a "criteria pollutant" by the Environmental Protection Agency (EPA), carbon dioxide (CO_2) is a gas associated with the widespread use of fossil fuels, such as coal, oil, and natural gas, and other carbon-based fuels, including wood. Industrial processes and deforestation also contribute to increasing CO_2 levels. It is believed that growing concentrations of CO_2 in the atmosphere may cause global climate change because of CO_2's ability to trap heat in the earth's atmosphere. Methane and chlorofluorocarbon are other gases that may contribute to the greenhouse effect. Many researchers believe the buildup of these gases, referred to as greenhouse gases because they act much like the panes of glass in a greenhouse, may cause the earth's average temperature to rise. This warming could contribute to many environmental problems, such as reduced agricultural production in some areas, increased ocean levels with shoreline flooding from thermal expansion and glacial melting, and dramatic shifts in local ecological systems.

State governments do not typically monitor concentrations of CO_2 and other greenhouse gases. The Oregon Department of Energy (1990) did estimate Oregon's contributions to greenhouse gases, but these estimates were based on regional, national, and global averages, rather than on monitored data.

Earth's thermal stability is achieved by the balance between solar energy and thermal energy re-radiated into space. Water vapor, carbon dioxide, ozone, and other trace gases make up the earth's "atmospheric blanket," which effectively reduces the rate of loss of long-wave thermal energy into space from the earth's surface while allowing incoming solar shortwave radiation to pass unaffected. This accounts for the fact that global surface temperature is higher than would occur if the earth did not have an atmosphere.

Excepting ozone, increasing concentrations of these gases in the atmosphere increase the thickness of the blanket, which in turn increases the surface temperature of the earth. This is referred to as the greenhouse effect.

Ozone absorbs incoming solar ultraviolet (UV) shortwave radiation. When ozone is defrayed or diminished in the atmosphere, increased UV radiation strikes the earth's surface. This radiation is likely to increase rates of skin cancer in humans and stunt plant growth. Increased radiation is also likely to contribute to global warming.

The earth's climate results from complex interactions of atmosphere, oceans, continents, ice sheets, sea ice, and biota. Such interactions, or feedback mechanisms complicate model building and analysis of increasing atmospheric gases. The ocean, for example, is a huge CO_2 sink, absorbing approximately 40 percent of all CO_2 created by fossil fuel combustion. However, this absorption process is little understood, and the ultimate carrying capacity of the oceans for CO_2 is not known.

It has been established through the use of ice cores and atmospheric testing that the concentration of CO_2 in the atmosphere is higher than it has been in the last 160,000 years. The U.S. is the leading emitter of CO_2; the former USSR is second. Developed countries are now reducing their per capita emissions, and the developing nations with rapidly growing populations are now responsible for the major increases in CO_2 emissions.

The rate of global CO_2 emission increased steadily by 4.6 percent per year until 1973, then declined to a rate of 2.3 percent per year.

Partly because the PNW relies heavily on hydropower, it is low on the national ranking for CO_2 emissions. However, meeting high electric load growth would quickly exhaust cost-effective supplies of conservation and renewables. If resources using organic fuels were then relied upon, the PNW could significantly increase its amount of CO_2 emissions in the future.

Many models of the greenhouse effect show global increases in temperatures of 1.2 to 1.3 degrees Celsius (oC) due to doubling of CO_2 concentrations. Because of the many variables involved, there is uncertainty surrounding this issue. There seems to be a pattern that CO_2 increases surface warming and that feedback mechanisms increase the earth's relative humidity, which in turn may cause a rise in surface temperature. With feedback mechanisms figured in, results show a warming of 3.5 to 4.2 oC. Regional patterns are difficult to gauge and would vary depending upon location.

It is uncertain what effects global warming would have on the PNW. Mean temperature changes do not show effects on seasons, precipitation patterns, or the kind of weather pattern formed over the region. Power production, temperature, and precipitation are closely related. For example, heavy rains in the mountains are not as valuable for power generation as a heavy snow pack. Similarly, a significant reduction in precipitation would result in a dramatic reduction in hydropower generation.

2.5.2 California Air Quality Regulation

In an effort to address California's unique air quality problems and to establish new procedures and strategies to address the continuing nonattainment air districts, California adopted its own California Clean Air Act (CCAA) in 1988. Many areas of California are currently violating national and California ambient air quality standards. Appendix G, Part 2, shows California ambient air quality areas for ozone and particulate matter of less than 10 microns (PM10).

CCAA provisions continue to be the most stringent air regulations in the nation. CCAA allows local air districts to adopt rules and regulations governing indirect and area-wide emission sources and some mobile sources. Figure 2-6 shows California electric utility service areas and California air basins. CCAA also requires that air districts develop and adopt air quality attainment plans to address attainment of national and state air quality goals and establish procedures to attain ambient air quality standards. CCAA requires reduction of emissions of nonattainment pollutants by 5 percent per year. To achieve CCAA's objectives, the attainment plans must include more restrictive emission limitations from existing sources and procedures for permitting new sources.

The success of any of California's 14 air basin attainment plans depends on a number of regulatory controls. First, throughout California, most air quality problems are due to fossil fuel used by motor vehicles. The California Air Resources Board and several local air districts advocate electrification of transportation to help clean the air. The integration of electric vehicles with the electricity system raises some concerns, such as how recharging vehicles will affect the efficient operation of the utility system.

Second, utilities and air districts are developing emission controls and changing power plant emissions. For example, the South Coast Air Quality Management District (SCAQMD) regulates five utilities--SCE, Los Angeles Department of Water & Power, and the cities of Burbank, Glendale, and Pasadena --and has adopted emission limitation rules requiring retrofits for power plants. In 1989, SCAQMD adopted Rule 1134, which establishes NOx emission limitations for existing combustion turbines, and Rule 1135, which establishes NOx requirements for existing utility boilers or requires their replacement. Rule 1135 permits the utility to retrofit boilers with post-combustion emission controls and to repower boiler capacity or to replace the capacity with alternative resources. Rule 1135 also establishes maximum daily average NOx rates and daily and annual emission caps for each of the five utilities. The emission caps are the maximum pounds NOx per day that each utility's generating system within the district may emit. The emission rates are the allowable daily average of NOx emission in the district given in pounds of NOx per net MWh generated in the district. These limits include the 0.15 lb/MWh daily emissions rate, the 13,400 lb daily emissions mass cap, and the 1,640 tons/year annual emissions mass cap.

The San Diego Air Quality District is proposing Rule 69, which would reduce NOx emissions from existing boilers. Similar to SCAQMD's Rule 1135, Rule 69 directs SDG&E to meet reduced emission levels by 1996.

A critical assumption for ER 92 is that each utility system must conform with applicable air district best available retrofit control technology (BARCT) rules. However, the only air districts that currently have adopted BARCT rules for electricity generating facilities are the SCAQMD and the Ventura County Air Pollution Control District (APCD). For other districts that are expected to adopt rules, the Commission incorporated in ER 92 analyzes assumptions as to expected requirements based on existing review of air quality management plans or draft rules.

ER 92 assumed that all new combustion resource additions would use best available control technology (BACT) and would require emission offsets, except for repowering projects in SCAQMD. It assumes repowering projects in SCAQMD only obtain offsets for that portion of

the project greater than the original MW rating of the facility. Utility-specific air quality-related assumptions are reproduced in Appendix G.

Methods for reducing criteria pollutants may include purchasing offsets, assigning residual emission values, and using PNW seasonal exchanges. Offsets are emission reduction credits that a new California facility must acquire to prevent an increase in actual annual emissions in a nonattainment area. Offset requirements are administered by local air districts and are set on a site-specific basis. The air quality impacts of a new project may be offset by the shutdown of another source owned by the utility or by reduced emissions from a third-party market. Most parties need to obtain offsets for generation in excess of current capacity.

Residual emissions are those remaining after meeting all air quality rules such as "BACT" and offset requirements. If the utility can reduce those residual emissions, the reduction provides a net benefit to society. Consequently, if a new plant can displace an existing plant's emission, the benefit derived from that reduction should be accounted for when determining the cost-effectiveness of the new resource. California regulators include environmental cost adjustments as part of the determination of the cost-effectiveness of proposed resources. Environmental cost adjustments are for land and water impacts, NOx, visibility considerations, (SOx), and TSP.

Figure 2-6
Electric Utility Service Areas and California Air Basins
Figure (Page2-20 Electric Utility Service...)

2.5.3 Water

River Uses

The two major PNW rivers, the Columbia and the Snake, are very different now from when the region was first settled by non-Native American people. The large size and drop in elevation of the Columbia and Snake 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 projects are also operated to accommodate fish, wildlife, and recreation needs. Today there are 31 Federal hydro projects in the Columbia River Basin, including five major storage reservoirs--Libby, Hungry Horse, Albeni Falls, Grand Coulee, and Dworshak.

The sometimes competing multiple uses are considered by the hydro project owners and operators (the COE and the Bureau of Reclamation), 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 COE 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.

Recreation. In the PNW, 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 activities; other recreational opportunities include camping, picnicking, sightseeing, hiking, and hunting. The Columbia River Gorge has become a world-class destination for 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 the multiple uses. 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.

Irrigation. The dams in the Columbia River Basin provide water and power for irrigation.

The largest irrigation project in the Columbia River Basin is the U.S. Bureau of Reclamation's Columbia Basin Project, which serves approximately 225,337 hectares(ha) (556,800 acres). Only about half of this project's authorized capacity has been completed; environmental impacts from further development of the Project are being assessed in another environmental impact statement.

The Grand Coulee Reservoir provides irrigation for the Columbia Basin Project. Most of the water for the Project--about 3.3 km3 (2.7 MAF) annually--is pumped from Grand Coulee (Lake Roosevelt) into Banks Lake, which serves as an equalizing reservoir. Because the pumps in Lake Roosevelt are located at a fixed elevation in the pumping plant, low reservoir elevations

can hinder or prevent pumping. Pumps located at other reservoirs can be adjusted to accommodate fluctuations in water levels.

Another 25 cubic hectometers (hm3) (20,000 acre-feet) of irrigation water is withdrawn annually from the Columbia and Snake River confluence.

Flood Control and Navigation. Flood control is a priority use for most of the dams on the Columbia and Snake Rivers and their tributaries. The COE is responsible for managing flood control for the floodplains surrounding these water systems. By law, BPA cannot undertake any action that would interfere with or preempt this use of the reservoirs.

The Columbia and lower Snake Rivers also provide ship and barge transport of agricultural products downriver and of goods upriver to the interior of the region. These waterways are a primary transportation resource and thus major contributors to the region's economy. A portion of the storage capacity of those reservoirs, whose authority includes supplying water for navigation, is set aside to ensure that specified flows are maintained for that purpose.

Water Quality and Use

In general, the PNW enjoys excellent water quality. State reviews of water quality are summarized below. In reviewing water quality, the states often refer to designated uses and the Federal Clean Water Act's goals of fishable and swimmable waters. The EPA has established regulations that require at a minimum that, where attainable, all designated uses specify that water is fishable or swimmable. The Clean Water Act requires states to establish designated uses for which each body of water in the state must be maintained. The state must also establish pollution level criteria to maintain the designated use.

Nuclear, coal, oil, and gas-fired generating plants use water for cooling. Water is taken from rivers, aquifers, coastal waters, or reservoirs, and is recycled within the plant or returned to its source. Listed later in this section are water bodies that currently supply major thermal power plants.

Idaho has about 51,488 km (32,000 mi) of streams and rivers and 283,290 ha (700,000 acres) of lakes. About half of the stream miles and all of the lakes have been assessed for water quality. Of the waters assessed, about 7 percent experience point source impacts, such as pollutants discharged from power plants and other municipal and industrial sources. Nonpoint source pollutants impact 57 percent of the assessed streams and lakes. The key sources of nonpoint pollution include agriculture, forestry practices, and mining. To help manage nonpoint sources, Idaho has established best management practices, which are defined as a practice or combination of practices determined to be the most effective and practicable means of preventing or reducing the amount of pollution generated by nonpoint sources.

Montana has over 80,450 km (50,000 mi) of streams and rivers, almost 303,525 ha (750,000 acres) of lakes, and 809,400 ha (2 million acres) of wetlands. About 20,917 km (13,000 miles) of Montana streams and about 202,350 ha (500,000 acres) of lakes have one or more impaired uses. Only about 2 percent of Montana's lake area and stream miles do not meet the fishability goal of the Clean Water Act. An even smaller percentage of lakes and streams do not meet the swimability goal of the Act. Point sources of pollutants account for less than 10 percent of impaired surface waters. The leading sources of surface water pollution are

agriculture, natural habitat and hydrologic modification, resource extraction, forest practices, construction, and soil disposal.

Oregon has over 144,810 km (90,000 mi) of rivers and streams that cross or border the state, 6,000 lakes and reservoirs, and 21 major estuaries on 582 km (362 mi) of coastline. The

Oregon Department of Environmental Quality (ODEQ) estimates that 81 to 100 percent of river miles meet the fishability goal, and 91 to 100 percent meet the swimability goal. The total surface area of Oregon's lakes total more than 246,867 ha (610,000 acres). The ODEQ states that although many Oregon lakes have excellent water quality, problems are occurring from increased recreation and high nutrient levels. High mercury levels have also been found in some reservoirs. Oregon's tidal estuaries total 53,357 ha (131,844 acres), and freshwater wetlands are estimated to cover 12,141 ha (30,000 acres). Little is known about the water quality in these areas.

Washington has about 64,360 km (40,000 miles) of rivers and streams, with an additional 557 km (346 miles) of boundary rivers. The state has over 24,282 ha (60,000 acres) of lakes and reservoirs, 265 km (165 miles) of coastal shoreline, about 7,770 km2 (3,000 square miles) of estuaries, 161,880 ha (400,000 acres) of freshwater wetlands, and over 445,170 ha (1.1 million acres) of tidal wetlands. All coastal waters meet all Clean Water Act and designated use goals.

Washington has identified several special state concerns. These include an ongoing study of nonpoint source pollution from forestry practices, a management plan for Puget Sound, dioxin and heavy metal contamination in the Columbia River and Lake Roosevelt, improvement of water quality in the Spokane River, and an intensive study of the Yakima River Basin.

Sources of Water Used for Thermal Plant Cooling

The Yellowstone River in Montana, the Green River in Wyoming, the Skookumchuck River in Washington, and the Columbia River in Oregon supply water to cool existing thermal plants that serve the PNW.

Yellowstone River supplies water by pipeline to Castle Rock Reservoir, which supports a warm water fishery and supplies the water for the Colstrip coal plant, near Forsyth, Montana.
Point sources, such as the coal plant, are listed as being of slight magnitude in impacting the middle basin of the Yellowstone River. 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 area. Precipitation and run-off in the

area are low. (Montana Department Health and Environmental Sciences 1990).

Green River, near Green River, Wyoming, supplies water for the Bridger coal plant. It is regulated at Fontenelle Reservoir. This river supports a blue ribbon fishery for brown and rainbow trout. The historical mean annual discharge is 50 m3/sec (1,763 cfs). Minimum discharge occurs in the winter, 19 m3/sec (688 cfs) in February 1984.

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. The Skookumchuck is not listed as being water quality limited.

Columbia River (Carty Reservoir) supplies water for irrigation and for cooling the Boardman coal plant. That 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 would supply cooling water to the Creston Power Plant near Creston, Washington, should it be built. The Columbia River near Creston is part of the Franklin D. Roosevelt Reservoir. The reservoir supports a popular recreational fishery for walleye, sturgeon, and resident salmonids. Discharge water would be returned to cooling ponds and not to the Columbia River. The Columbia River also supplies cooling water to the WNP-2 nuclear plant at Hanford, Washington.

Key concerns identified for the Columbia River include dioxin pollution and heavy metal contamination. The dioxin appears to originate from pulp and paper mills using a chlorine bleaching process. Metal contamination has been traced to lead and zinc mines in British Columbia, Canada. No key concerns are associated with electric power production. (Washington State Department of Ecology 1990, and ODEQ 1990.)

Humboldt River Basin groundwater supplies the Valmy coal plant in Nevada. The aquifer also supplies domestic consumption and livestock.

2.5.4 Vegetation and Wildlife

A description of Western States vegetation and wildlife details are found in Appendix G, Part 6. Information on threatened or endangered species in the affected area is contained in Appendix D.

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CHAPTER 3 ALTERNATIVES INCLUDING THE PROPOSED ACTION 1

BPA is considering action in two areas: (1) non-Federal access to the AC Intertie, and, (2) BPA Intertie marketing. BPA's preferred alternative for non-Federal access is to combine the Capacity Ownership alternative and the Increased Assured Delivery alternative; the preferred alternative for BPA Intertie marketing is the Federal Marketing and Joint Ventures alternative.

This eis refers to the separate options in both areas as "alternatives," even though they are not all alternatives to each other in the literal sense of being mutually exclusive. The alternatives eventually adopted may include action in both areas; therefore, the analysis covers cumulative cases showing the impacts of added non-Federal Intertie access plus added Federal marketing and joint ventures. The choices open to BPA are probably best envisioned as continuous ranges of possible policy choices affecting the four major business factors described below: 1) non-Federal Intertie access amount; 2) non-Federal user flexibility; 3) firm versus nonfirm use of the Intertie; and 4) overall Intertie use for different transaction mixes.

3.1 Major Business Factors Affected by the Alternatives

The choices available to BPA with respect to Intertie access and marketing can be appreciated in terms of four major business factors -- amount of transmission access in MWs, flexibility of access, use of the Intertie for firm or nonfirm transactions, and predominant transaction types. The alternatives can be seen as points or ranges on a continuum. Changes in these business factors can lead to changes in utility decisionmaking, discussed in Section 3.2.

3.1.1 Non-Federal Access - MW

The first business factor is the amount of Intertie capacity in megawatts that is made available by BPA for firm access for non-Federal uses. This factor controls the potential maximum size of power transactions. Under the No Action alternative with the LTIAP, this amount has been 800 MW for Assured Delivery requesters with some additional access available for parties entering into joint ventures with BPA. Future applications of the Energy Policy Act of 1992, Title VII Section 721, providing for increased transmission access to requesting entities, could result in increased availability. BPA's Capacity Ownership proposal (described in detail in Appendix A) identified 725 MW as potentially available for non-Federal access. Non-Federal parties have expressed interest in even greater MW amounts. Also, potential joint ventures under BPA's Federal Marketing and Joint Ventures alternative may provide expanded non-Federal access.

3.1.2 Non-Federal Access - User Flexibility

The second business factor is how much flexibility of non-Federal use of BPA transmission facilities is provided under an alternative. When a utility builds, owns, and operates transmission facilities independently, it retains maximum flexibility to use them. In reality, owners must often compromise their autonomy if the transmission involves interconnection and interchange with other systems. The needs and conditions on a neighboring system may constrain maximum firm access and may temporarily reduce access due to system technical problems. Utilities having transmission contracts to use facilities that are built, owned, or operated wholly or partially by others have less flexibility over the use of the transmission line. Their decisionmaking is constrained by the terms of the contracts.

3.1.3 Intertie Use - Short-Term vs. Long-Term Contracts

The third business factor is whether an alternative provides for or encourages short-term versus long-term transactions. Short-term interregional transactions have significant economic and efficiency benefits and may aid displacement of generation by thermal fueled plants. Long-term firm transactions can provide these benefits and also defer long-term resource acquisition needs in one system by making use of available excess capacity or energy from another system.

3.1.4 Transaction Types

BPA's IDU eis found that there were environmentally significant differences between firm power sales versus seasonal exchange transactions. Therefore, the NFP eis analysis will study scenarios in which potential hypothetical contracts are predominantly either firm power sale or seasonal exchange. These generic contract scenarios will necessarily be oversimplified compared to real contracts. Power contracts are widely variable in the products and services provided. The studies of impacts for this eis contrast firm power sales in which the transfer is uni-directional, versus seasonal exchanges in which the transfer is bi-directional. It is possible to negotiate contracts that have features of both. Firm power sales and seasonal exchange were used as examples for this analysis because they have distinctly different implications for the operation of the PNW system and present environmentally different issues. Firm power sales contracts are exports out of the PNW, which add to the seller's obligations to serve and therefore, in some circumstances, to the probability of need for resource acquisition. Firm power purchases decrease the buyer's resource acquisition needs. Firm seasonal exchanges may decrease both parties' need for resource acquisition to meet peak seasonal loads and may change the pattern of resource operations during the year. When seasonal load diversity exists as it does between the PNW and PSW regions, seasonal exchanges would often be expected to have the highest net value. However, individual utility characteristics may make seasonal exchanges less desirable than firm power sales. For these cases, a firm contract which does not require the return of energy or capacity is most economic. Some typical transactions are as follows:

Seasonal exchanges. Seasonal exchanges can be arranged to provide somewhat different services to the parties and use resources differently:

(1) Seasonal capacity-for-energy exchange: the PSW party receives a certain level of capacity during peak load hours from the PNW party. The energy associated with the on-peak capacity delivery is returned to the PNW within 24 hours. This preserves the energy content of the PNW hydro system on a daily basis. Instead of a dollar payment for the on-peak capacity, "exchange energy" is delivered back to the PNW in a different season, usually off-peak. Hydro storage can preserve the off-peak delivery for use during heavy load hours.

(2) Under a seasonal power-for-power exchange, power, i.e., energy at a stated capacity level, is delivered to the PSW during peak hours and power is returned, usually in a different season, also during on-peak hours. There is no 24-hour return of energy, so some energy content of the PNW hydro system is "spent" in one season with capacity and returned in another.

(3) Under a seasonal power-for-energy exchange, power is delivered to the PSW and an amount of energy, at some negotiated ratio in lieu of a dollar payment, is returned off-peak to the PNW in a different season, normally during off-peak hours.

(4) Seasonal "environmental" exchanges resemble seasonal power-for-energy exchanges except the shape, delivery time, and energy return is established on a case-by-case basis to maximize environmental as well as economic benefit. These exchanges take advantage of PNW seasonal surpluses due to hydro operations for fish and address the need to reduce NOx emissions in California. In 1991 and 1992, short-term seasonal environmental exchanges were entered into between several California parties and BPA.

Firm power sales. Firm power sales can also take different forms. BPA and PNW utilities currently have several long-term surplus power sales contracts with California utilities. In general, they fall into two categories:

(1) system sales supplied from a mix of resources, and
(2) sales of output from a specific generating resource.

BPA's surplus firm power transactions are system sales. Often, they have been negotiated with the flexibility to convert annually to capacity for energy exchanges if BPA determines that it does not have adequate surplus firm power available for sale. Firm power sales by other PNW utilities which have been given Intertie access under BPA's LTIAP have been of both types. Joint venture arrangements in which BPA and a utility together supply a product for sale or exchange may combine some features of a system sale with a specific non-Federal generating resource.

3.2 From Business Factors to Utility Decisions to the Environment

Changes in business factors change the context in which utilities make decisions. Utility decisions result in actions that may have environmental effects. The business factors described above related to Intertie use are only a portion of that context. Other key components of the context are individual utility load growth, financial condition, existing system resources, the

local and national economy, regulatory provisions, and customer and other public opinion. The utility decision areas most likely to be affected by the alternatives studied in this eis are:

(1) operation of generating resources, and
(2) conservation and other resource development.

The following discussions describe some of the specific changes that may be made to resource operations and development of conservation and other resources.

3.2.1 Operation Of Generating Resources

Generally, utilities make decisions on resource operation in a relatively short timeframe based on costs of resource operation. In some areas, owners may adjust resource operations in relation to changes in local air quality. The alternatives studied here do not affect basic costs of construction, or operation, nor air quality regulation. They may affect access to markets and thus the ability to displace or defer costs.

BPA Resource Operations. BPA's system is a mix of hydro and thermal resources BPA can use to meet generation needs. (See Appendix F for a description of PNW hydro operating principles.) BPA marketing actions become Federal system obligations served from this resource mix. BPA makes actual operating decisions, that is, which resource to operate at what level, by taking into account the best economic and environmental total operation. Hydro operations on the Columbia River are increasingly under review due to the tensions among multiple uses, especially the need to protect endangered salmon species. BPA is currently participating with other agencies in two resources forums: first, development of a salmon recovery plan in compliance with the ESA; and second, the SOR, a public process to determine the multi-purpose operating guidelines for Columbia River facilities.

The BPA marketing proposal studied here will not prejudice hydro operation decisions. Hydro operation decisions will be made in the forums created for them. BPA will operate the resources in its mix consistent with those decisions.

PNW Non-BPA Resource Operations. Non-BPA regional resources are also mixed hydro and thermal with a higher proportion of thermal resources, especially for IOUs. (See Chapter 2, Affected Environment.) Enhanced non-Federal access to the Intertie generally removes a barrier to long- and short-term interregional marketing. Depending on the transaction, PNW resources may be displaced or operated to a greater degree.

PSW/ISW Resource Operations. The resources in these regions are predominantly thermal--coal, nuclear, and natural gas--with some hydro generation. (See Chapter 2, Affected Environment.) Increased market access for PNW energy facilitates displacement of relatively expensive, less efficient, and environmentally harmful PSW and ISW resources. Resource operations in the State of California may be directly influenced by real-time air quality factors.

3.2.2 Conservation and Generating Resource Acquisition

BPA Resource Acquisition. BPA's resource acquisitions are directed by its Resource Program process. BPA's marketing proposal in the Federal Marketing and Joint Venture alternative emphasizes seasonal exchanges, which generally would offset the need to acquire new resources. Environmental costs and benefits are included in the analysis for BPA's Resource Programs.

PNW Non-BPA Development. Removal of a marketing barrier such as lack of transmission access may defer or advance new resource development, depending on the transaction type. The types of resources likely to be developed by PNW non-Federal parties are much the same as those likely to be developed or acquired by BPA but may be arranged in somewhat different priority. BPA's Resource Program contains more conservation than the resource plans of many non-Federal utilities. "Resource stacks" are lists of resources arranged in order of desirability. Levelized cost is often the first factor used to prioritize resources. For BPA's resource stack as shown in the 1992 Resource Program and in the Resource Programs eis, the resource priorities have been adjusted to include environmental "externalities," i.e., environmental costs and benefits. The resource stacks of PNW non-Federal utilities and independent resource developers have not necessarily incorporated environmental externalities. This results in less emphasis on certain conservation programs and on earlier development of natural gas-fired plants, including cogeneration facilities, and new coal plants.

PSW Development. California State resource planning and acquisition processes are summarized in Chapter 2. The CEC applies cost-effectiveness criteria to new resources, including contractual resources for imports or exchanges with other regions. To some degree, the CEC's planning includes some future transactions with PNW parties or Canada. Increased transmission access and marketing from PNW parties may allow for contractual arrangements that defer other California resource acquisitions.

3.3 Description of the Alternatives

Table 3-1 Summary of NFP eis Alternatives

Alternative:	Features:
No Action	. Non-Federal access under LTIAP only.
	. All 800 MW allocated for Assured Delivery assumed fully used in accordance with LTIAP Exhibit B limitations.
	. Federal marketing and joint ventures with PSW parties assumed to be existing contracts only.
	. Third AC assumed operational.
Non-Federal Intertie Access Alternatives	
Capacity Ownership	. Non-Federal access under LTIAP assumed to remain fully used.
	. 725 MW open for Capacity Ownership, assumed fully used.

scenarios: seasonal exchanges, firm

- Two generic contract power sales.

included beyond the preferred 725 MW

- Additional scenario offer with 1,450 MW assumed

available for Capacity Ownership.

Increased Assured
LTIAP Exhibit B.
Delivery
1,525 MW (725 MW + potential

- 725 MW added to 800 MW
- Additional scenario with 800 MW more). Also looks

at removal of current LTIAP

constraints on contract

type.
Increased Assured
Delivery except assumes that non-
Delivery -- Access for
interested in Capacity Ownership are
Non-Scheduling
Delivery.
Utilities
Economic Priority
meet contract-specific economic

- Same as Increased Assured scheduling parties eligible for Assured
- Non-Federal access must benefit test to be applied

by BPA.

scenarios: seasonal exchanges, firm

- Two generic contract power sales.

BPA Intertie Marketing Alternatives
Federal Marketing &
to increase value of hydro fish
Joint Ventures

- Assumes new BPA contracts operations.
- New contracts would use

hydro flows for fish. Contracts to be

flexible as to type and

size.

- Example generic contracts

studied: (A) 1,100 MW seasonal

exchange of BPA

power/capacity for fall/winter energy,

(B) 1,100 MW joint venture

10-month firm power sale with

2-month power/energy

exchange.

- Non-Federal access via

joint ventures.

- Additional scenario

addresses potential contracts up to

2,200 MW.

3.3.1 No Action Alternative

The No Action alternative applies to both areas under consideration: non-Federal Intertie access and BPA Intertie marketing. Briefly, No Action for non-Federal access means access only under the terms of the May 1988 LTIAP. No Action for BPA marketing means no new contracts -- only existing BPA marketing and joint venture agreements. Under Section 721 of the Energy Policy Act of 1992, the No Action alternative may imply increased non-Federal access via requests to the FERC. For purposes of analysis, no new long-term BPA bilateral or joint venture contracts using the Intertie were assumed.

Non-Federal Access - MW. Firm non-Federal access to BPA's share of total Intertie capacity (6,550 MW once the Third AC project is fully in operation) is assumed to be limited to the 800 MW of Assured Delivery rights specified in the May 1988 LTIAP. The eis analysis retains this as an assumption for purposes of analysis, but the transmission access provisions of Section 721 of the Energy Policy Act of 1992 give FERC authority over Intertie transmission and could result in approval of access beyond the LTIAP limits. This possibility of increased access under the Energy Policy Act would apply to all alternatives. However, the analysis assumes current BPA policies for the No Action case.

Non-Federal Access - User Flexibility. Under the LTIAP, BPA provides firm Assured Delivery on its share of the combined capacity of the AC and DC Interties to PNW scheduling utilities, that is, utilities that own significant amounts of generation that they control to meet their own hourly loads. (Most of BPA's PNW customers are non-scheduling utilities owning little or no generation. BPA's generation control system operates resources to meet the hourly loads of these utilities.) Entities other than PNW scheduling utilities must arrange through BPA or another scheduling utility to obtain firm Intertie transmission services. Access for short-term sales is provided for PNW scheduling utilities and, under certain conditions, for Canadian utilities. Short-term sales, such as monthly, daily, or hourly sales, receive hourly allocations.

The May 1988 LTIAP places certain conditions on Assured Delivery:

(1) access for firm power sales are limited to a maximum hourly MW limit equal to the average energy firm surplus of each scheduling utility (developed for the 1988 LTIAP from 1986 regional resource data);

(2) firm exports of new resources are limited by the Exhibit B 800 MW amount, and for each utility by the individual utility average energy firm surpluses (The LTIAP provides for BPA to update the utility average energy firm surpluses, but this hasn't

been done to date);

(3) the total of all Assured Delivery contracts may not exceed 800 MW, although joint venture contracts involving BPA and another utility are not subject to this limit;

(4) the utility receiving Assured Delivery may not wheel miscellaneous nonfirm or third party power;

(5) the utility must agree not to request additions to its future BPA firm load requirements service to the extent of a firm power export in accordance with a provision of the Northwest Power Act, Sections 9(c) and (d) and Section 3(d) of Public Law 88-552 (The Northwest Preference Act.); and

(6) transmission of power from resources in Protected Areas is prohibited.

The LTIAP also allows for non-Federal access via joint ventures not subject to the same conditions as Assured Delivery. Since joint ventures require BPA and the utility to jointly negotiate a contract, there is less utility autonomy. Some joint ventures have been negotiated.

Intertie Use - Short-Term vs. Long-Term Contracts. The No Action alternative would allow for up to 800 MW firm non-Federal Intertie use as well as BPA's firm Intertie contracts. The LTIAP does not limit the amount of firm transactions BPA can enter into as bilateral contracts or with other utilities as joint ventures.

Transaction Types. Under the LTIAP, BPA has set aside a maximum of 800 MW for Assured Delivery. Of that 800 MW, a maximum of 444 MW is available for Assured Delivery for firm power transactions. This 444 MW level was the sum of the annual firm energy surpluses of PNW scheduling utilities just prior to the adoption of the LTIAP in 1988. Assured Delivery firm power transactions must be equal to or less than the utility's average energy firm surplus. BPA's determinations of such surpluses are listed in Exhibit B to the LTIAP. The LTIAP does not provide for the 444 MW total of utility firm surpluses to be increased, although BPA may decrease it as surpluses decline. The remaining 356 MW is earmarked for seasonal exchange transactions. This is currently completely used by two approved Assured Delivery exchanges. The LTIAP provides that a scheduling utility may support its long-term firm power sales or exchanges with existing or new resources, excepting resources in Protected Areas. A utility may use all or part of its Exhibit B amount for Assured Delivery for a seasonal exchange.

BPA's extraregional marketing under the No Action case would be the continuation of existing
contracts and assumed future short-term marketing or exchange arrangements. No new long-
term firm BPA agreements would be assumed.

Under this alternative, the current amount of capacity available for Assured Delivery pursuant
to the LTIAP, 800 MW, would not be increased. BPA's share of the increased capacity from
the Third AC project would belong to BPA and could be used for BPA marketing or joint
ventures or for nonfirm access under the LTIAP.

3.3.2 Capacity Ownership

BPA's preferred alternative for providing non-Federal Intertie access is to adopt Capacity Ownership for 725 MW together with Increased Assured Delivery. Capacity ownership would allow non-Federal PNW scheduling utilities to purchase contract rights to use portions of BPA's share of AC Intertie capacity for the life of the Intertie facilities. A description of BPA's Capacity Ownership proposal is included in Appendix A.

Non-Federal Access - MW. The amount of capacity BPA proposes to make available for capacity ownership is 725 MW, assuming a total AC Intertie rating of 4,800 MW. (See Appendix A, Life of Facilities Capacity Ownership Proposal.) The price to be paid for capacity ownership is $215/kW (in 1993 dollars), based on mid-1989 estimates of costs. BPA would adjust this price after commercial operation of the Third AC Intertie to reflect actual costs for facilities referred to in Appendix A, Table A-1.

Interested PNW parties with Memoranda of Understanding (MOUs) have requested between 1,170 MW and 1,542 MW of capacity ownership (see Table 3-2, page 3-9). This has required BPA to address two issues: (1) allocation of 725 MW among requesting parties, and (2) offering capacity above 725 MW.

Eleven utilities signed MOUs showing interest in non-Federal participation. After the MOUs were signed, BPA developed a proposed methodology for allocation of the 725 MW of capacity proposed for Capacity Ownership. To establish BPA's initial position for contract negotiations, BPA quantified the capacity shares to be allocated to utilities that met the requirements set forth

in the proposed methodology. Only six utilities met requirements for a preliminary allocation under the proposed methodology. These six utilities currently are participating in development of a potential capacity ownership contract.

Table 3-2 Parties with Memoranda of Understanding for Capacity Ownership

	Party	MW	Contingencies
1	Puget Sound Power & Light	400	None
2	Emerald PUD	130	None
3	PacifiCorp	200-300	Sale to California party
4	Seattle City Light	165-220	" "
5	Clark PUD	50-150	" "
6	Grays Harbor PUD I	53-90	" "
7	Mason PUD No. 3	25-50	" "
8	Snohomish PUD	25-50	" "
9	Eugene Water & Electric Board	30-50	" "
10	Tacoma City Light (TCL)	40-50	Assured Delivery decision
11	Pacific Northwest Generating Company (PNGC)	52	Sale to California party, BPA approval, etc.

The following utilities received preliminary allocations in the amounts indicated:

Utility	Preliminary Allocation (MW)
Puget Sound P&L	371 MW
Seattle City Light	160 MW
Tacoma Public Utilities (TCL)	50 MW
Snohomish PUD	42 MW
Eugene W&EB	50 MW
PNGC	52 MW

With respect to allocations of capacity ownership, BPA has conducted a public review process considering alternative criteria for allocating the offered 725 MW among the interested parties. See Appendix A for descriptions of the alternative allocation criteria. The allocation criteria considered included: (1) pro rata based on requested MWs; (2) whether the party already owned Intertie capacity; (3) whether the proposed transaction provided best net benefits; and

(4) whether the party placed conditions on its MOU. Different combinations of these criteria were considered. After considering comment from this process, BPA proposed an allocation methodology that would give priority to entities that do not currently own other Intertie capacity and to those that signed "unconditional" MOUs. (The MOUs indicate whether the utility's request to buy capacity ownership was conditioned on future execution of a contract with a PSW party or some other occurrence. See Table 3-2.) This eis does not separately analyze each of the alternative combinations of allocation criteria but contrasts outcomes for two factors considered to have some potential environmental implication. The first factor is whether the final allocation results in access for parties that are more likely to engage in seasonal exchanges than firm power sales or vice versa. The second factor is whether the allocation results in capacity ownership predominantly for generating preference customers or a split between these customers and IOUs in the ratio represented by the MW requests. It should be noted that the proposed allocation criteria would not use either of these factors directly to make the allocation. These scenarios are used for the eis analysis because they will help bound the likely impacts of the Capacity Ownership alternative.

Some parties have also suggested that BPA consider offering more than 725 MW for non-Federal participation. The analysis of this alternative will address the effects of Capacity Ownership of a greater amount of Intertie capacity up to 1,450 MW. However, BPA's preferred alternative is to offer 725 MW for Capacity Ownership and retain the remaining capacity for Federal use.

Non-Federal Access - Flexibility of Use. Under the capacity ownership alternative, capacity owners would be able to use their capacity share without regulation by BPA except in three areas:

(1) LTIAP provisions prohibiting Intertie access for generation resources located in Protected Areas will continue to apply to the owners, and
(2) An owner may provide wheeling for third parties only if the owner has elected to waive any access to BPA's capacity under the LTIAP. (Formula Allocation and Exhibit B Assured Delivery).
(3) Proposed exports would be reviewed by BPA under Section 9(c) of the Northwest Power Act and Section 3(d) of P.L. 88-552, the Northwest Preference Act.

Non-Federal flexibility of use would also be affected by provisions in the Capacity Ownership proposal relating to PNW Power Act Section 9(c) and (d) and Section 3(d) of Northwest Preference Act. These statute sections deal with important concepts having to do with the relationship between a BPA customer's export actions and its rights to BPA firm service for its PNW load. Because important legal rights and obligations are involved, this eis does not attempt to translate the legal concepts into lay language. For further detail, see Appendix A, which includes a previously published BPA document on this matter. It is proposed that the Capacity Ownership alternative include a BPA policy determination under PNW Power Act Section 9(c) on the parties' proposed exports. BPA is providing a public review and comment process on this determination. The determination will address proposed exports via Capacity Ownership in the 725 MWs proposed here. The determination will identify, consistent with

PNW Power Act Section 9(c) and (d) and Section 3(d) of the Northwest Preference Act, those resources which, if exported, would not be subject to a reduction in the utility's firm service provided by BPA because the export of such resources will not result in an increase in BPA's obligations to that customer or any other customer for service to firm loads in the region or such resources could not be conserved or otherwise retained for service to regional loads.

Intertie Use - Short-Term vs. Long Term-Contracts. The capacity ownership alternative is expected to increase the amount of long-term firm contracts using the Intertie compared to the No Action alternative, in which the LTIAP limits the amounts of firm Assured Delivery transactions and the use of new resources.

Transaction Types. Because capacity ownership would not be subject to the LTIAP constraints on firm power sales, this alternative might increase the amounts of firm power sales contracts relative to exchanges if other market factors make firm sales attractive.

3.3.3 Increased Assured Delivery

Under this alternative it is assumed that BPA would use 725 MW additional Third AC capacity to increase the amount of non-Federal access.

Non-Federal Access - MW. The Assured Delivery ceiling in Exhibit B of the LTIAP, 800 MW, is assumed to be increased by 725 MW for a total of 1,525 MW. Section 721 of the Energy Policy Act of 1992 may lead to greater access.

Non-Federal Access - User Flexibility. As under the LTIAP, it will be assumed that a scheduling utility may support its long-term firm power sales or seasonal exchanges with existing or new resources, excepting resources in Protected Areas. Section 721 of the Energy Policy Act of 1992 may also lead to greater flexibility.

Intertie Use - Short-Term vs. Long-Term Contracts. This alternative may lead to increased use of the Intertie for long-term versus short-term transactions.

Transaction Types. The added capacity could be used for seasonal exchanges or firm power sales. The terms of the LTIAP imply that, when the PNW load-resource balance shows no firm power surplus, the Exhibit B MW limits on transmission access for firm power sales would apply to Assured Delivery requests. However, the LTIAP provides for future BPA revision. Also, Section 721 of the Energy Policy Act of 1992 may result in changes to the LTIAP.

3.3.4 Increased Assured Delivery With Intertie Access for Non-Scheduling Utilities

Under this alternative, Assured Delivery Intertie access would be made available directly to PNW non-scheduling utilities, instead of via BPA or a scheduling utility as under the LTIAP.
Some non-scheduling utilities have expressed interest in participating in the Third AC: Emerald PUD (130 MW), Clark County PUD (50-150 MW), Grays Harbor PUD (53 to 90 MW), Mason County PUD No. 3 (25 to 50 MW), and the utility members of the Pacific Northwest

Generating Company (52 MW). Under the LTIAP, these non-scheduling utilities must request Intertie access through BPA or the scheduling utility in whose generation control area the resource is located. BPA has offered to provide Intertie access to these parties via joint ventures under the LTIAP, which would help BPA dispose of its surplus power.

Non-Federal Access - MW. The Assured Delivery ceiling would be the same as for the Increased Assured Delivery alternative, increasing the LTIAP's 800 MW of Assured Delivery by 725 MW, for a total of 1,525 MW. Access would be extended to a wider group of utilities.
Section 721 of the Energy Policy Act of 1992 may lead to greater access.

Non-Federal Access - User Flexibility. Non-scheduling utilities would gain increased autonomy by qualifying for Assured Delivery under the LTIAP. They would still require contractual arrangements with BPA for services to integrate their resource for delivery over the Intertie.

Intertie Use - Short-Term vs. Long-Term Contracts. This alternative could result in more long-term firm transactions than the No Action case. It would not be markedly different from other cases.

Transaction Types. This alternative may influence the Intertie transaction mix in the direction of firm power sales in that some proposals by non-scheduling utilities are intended to market the output of certain generating resource shares they own. Also, these utilities generally lack the technical capability to independently manage an exchange transaction. They would require services to do so at added cost. Therefore, it is assumed that the transactions would likely be firm power sales rather than seasonal exchanges.

3.3.5 Economic Priority

Under this alternative, BPA would maintain ownership and control of expanded AC Intertie capacity. Access to the Intertie would be provided on a nondiscriminatory basis to any entity whose transaction meets a standard economic priority test. This alternative is not considered to result in different projected transactions because market forces tend to select for the transactions with greatest net economic benefit. The major difference in this alternative compared to the others would be that transmission access would remain uncertain until permitted by BPA in accordance with an economic test.

Non-Federal Access - MW. The amount of non-Federal access was not specified for this alternative. It could be somewhat larger than under the No Action alternative if it is assumed that utility transactions would meet the economic test.

Non-Federal Access - User Flexibility. With respect to long-term firm transactions, this alternative would require that the projected total economic benefits to the buyer and seller be analyzed through a standard methodology, to be developed in consultation with all parties. This contract-specific approval process would result in an unquantifiable business uncertainty relative to the Capacity Ownership alternative. In order to be granted firm, guaranteed access, a transaction would have to demonstrate at least an established level of total economic benefits.

The value of the transaction must be at least equal to the fully allocated cost of the transmission

capacity used for the period for which it is proposed to be used. This would include the opportunity cost of possible nonfirm sales over that same capacity. The factor for foregone opportunity costs would increase for longer-term transactions.

Under the Economic Priority alternative, utilities would be prohibited from supporting long-term transactions with resources in Protected Areas, or any new resource other than conservation or system efficiency improvements.

This alternative as originally proposed by the Northwest Conservation Act Coalition would have included an energy broker system for short-term market transactions on the 725 MW Third AC expansion. The alternative studied does not incorporate this economy market assumption for the following reasons. First, the impetus for considering non-Federal participation in the Third AC project was primarily long-term firm transactions. Second, the amount of economy marketing that would be expected for that 725 MW amount under the capacity ownership alternative would be minor. Given the size of the rest of the Intertie economy market, this small amount under a broker system would not produce distinguishable results. BPA provides access for short-term economy transactions under the LTIAP under procedures that allow market bidding in most situations.

Intertie Use - Short-Term vs. Long-Term Contracts. The Economic Priority alternative would permit either long-term or short-term transactions as long as they meet the economic test, but there is unquantifiable uncertainty due to the need for contract-specific access.

Transaction Types. This alternative would allow the economic needs of the parties to influence whether transactions were firm power sales or exchanges.

3.3.6 Federal Marketing and Joint Venture Proposal

This alternative is BPA's preferred alternative for Federal marketing. It is a BPA Marketing and Joint Venture package that would be responsive to recent changes in hydro operation requirements for endangered anadromous fish species. Recent operational decisions related to ESA processes have resulted in additional Columbia River flow requirements for fish passage in May and June. The Power Planning Council's latest Fish and Wildlife Program amendments called for storage of 3 MAF (3.7 km3) above the operations already required for the Water Budget. In practice, the amounts that can be stored and released may be less than 3 MAF, and it is possible that future ESA requirements may be larger. It is also possible that required flows for July may be increased, thereby increasing the amount available for export transactions. When released for fish flows, this stored water will lose value for meeting PNW power needs in other seasons. The spring releases may therefore increase BPA's need to acquire other resources for use in the winter, when the region's loads are heaviest.

Table 3-3 shows two example transactions. Example A is a BPA seasonal exchange with the PSW. Example B is a hypothetical joint venture with some firm power sale from PNW to PSW and some seasonal exchange.

Table 3-3 Examples of Generic Extraregional Transactions

Transaction Example A

MONTH	BPA Delivery (Monthly Average Energy and Capacity)	BPA Receipt (Monthly Average Energy and Capacity)
January	0	680 aMW/ 0 MW
February	0	680 aMW/ 0 MW
March	0	680 aMW/ 0 MW
April	0	0
May	1,100 aMW / 1,100 MW	0
June	1,100 aMW / 1,100 MW	0
July	0 aMW / 1,100 MW	0
August	0 aMW / 1,100 MW	0
September	0 aMW / 1,100 MW	0
October	0	680 aMW/ 0 MW
November	0	680 aMW/ 0 MW
December	0	680 aMW/ 0 MW

Transaction Example B

Transaction Example B

MONTH	Non-BPA Intertie Delivery (Monthly Average Energy and Capacity)	BPA Delivery and Return (Monthly Average Energy and Capacity)
January	1,100 aMW / 1,100 MW	- 445 aMW / 0 MW
February	1,100 aMW / 1,100 MW	- 445 aMW / 0 MW
March	1,100 aMW / 1,100 MW	- 445 aMW / 0 MW
April	1,100 aMW / 1,100 MW	0
May	0	1,100 aMW / 1,100 MW
June	0	1,100 aMW / 1,100 MW
July	1,100 aMW / 1,100 MW	0
August	1,100 aMW / 1,100 MW	0
September	1,100 aMW / 1,100 MW	0
October	1,100 aMW / 1,100 MW	- 445 aMW / 0 MW
November	1,100 aMW / 1,100 MW	- 445 aMW / 0 MW
December	1,100 aMW / 1,100 MW	- 445 aMW / 0 MW

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1 The capacity and energy amount shown here are examples only. BPA may choose to use more or less capacity and energy, depending on system availability given non-power operating needs and th benefits of possible individual contracts.

The proposed transactions may be BPA bilateral contracts with PSW parties or joint ventures involving BPA and other parties. As mentioned in Chapter 1, BPA is examining firm uses of the Northern Intertie between the PNW and Canada in the Bellingham eis. Depending on the outcome of that decision process, future Southern Intertie transactions may involve Canadian parties. Two generic examples are shown in Table 3-3 of a seasonal exchange and a transaction which is predominantly a firm power sale with some seasonal exchange of BPA spring flow energy. Future contracts could have several different types of provisions. They may combine some of BPA's Columbia River spring flow energy with energy or capacity or both from non-Federal resources for a period from approximately May through August, and possibly to September or October. PNW non-Federal resources may be given access as permitted under the LTIAP as joint ventures with BPA. The transactions with PSW and ISW parties may provide for return to the PNW of energy in winter months, making use of regional load diversities to increase use of existing generating resources and transmission and to delay the need for new Federal resource acquisitions. Any BPA sales of surplus Federal power as part of these transactions would be consistent with the requirements of the Northwest Power Act Sections 5(f) and 9(c), and the Northwest Preference Act, P.L. 88-552.

BPA will consider joint participation in various types of transactions, including seasonal energy exchanges, seasonal power exchanges, and seasonal capacity for energy exchanges. Columbia River generation would be used to the extent available. Other generation would be integrated as needed by short- or long-term BPA purchases or operating agreements and by use of joint venture resources. PNW non-Federal generation would likely come from existing cogeneration or thermal units such as Centralia or Boardman. Intertie access for new PNW resources is also possible as part of the joint venture arrangements proposed here. For instance, planned PNW resources could be brought on-line earlier because they would be economic for an export contract sooner than for PNW loads.

Non-Federal Access - MW. The amount of non-Federal access under this alternative could be greater than No Action to the extent that it encourages additional joint ventures.

Non-Federal Access - User Flexibility. Flexibility of non-Federal use could be increased relative to No Action because BPA would be willing to consider a wide variety of types of joint ventures. This alternative would not offer the same utility autonomy as Capacity Ownership so would contain some unquantifiable business uncertainty.

Intertie Use - Short-Term vs. Long-Term Contracts. The Federal Marketing and Joint Venture alternative would probably increase the expected use of the Intertie for firm transactions versus nonfirm marketing.

Transaction Types. This alternative might increase the probability of firm power sales as a major component of joint ventures. However, BPA's emphasis is on mutually beneficial seasonal exchanges.

CHAPTER 4 ENVIRONMENTAL CONSEQUENCES 1

4.1 Summary of Environmental Consequences

4.1.1 Alternatives

As mentioned previously, BPA is considering alternatives in two areas: first, non-Federal Intertie access; and second, BPA Intertie marketing. BPA's preferred alternative for non-Federal Intertie access is the Capacity Ownership alternative combined with the Increased Assured Delivery -- Access for Non-Scheduling Utilities alternative; the preferred alternative for BPA Intertie marketing is the Federal Marketing and Joint Venture alternative. The alternatives eventually adopted may include action in both areas.

Table 4-1 Summary of NFP eis Alternatives

Alternative: Features:

No Action . Non-Federal access under LTIAP only.

. All 800 MW allocated for Assured Delivery assumed fully used in accordance with LTIAP Exhibit B limitations.

. Federal marketing and joint ventures with PSW parties

assumed to be existing
contracts only.
. Third AC assumed
operational.

Non-Federal Intertie Access Alternatives

Capacity Ownership . Non-Federal access under
LTIAP assumed to remain fully
used.
. 725 MW open for Capacity
Ownership, assumed fully used.
. Two generic contract
scenarios: seasonal exchanges, firm
power sales.
. Additional scenario
included beyond the preferred 725 MW
offer with 1,450 MW
assumed available for Capacity
Ownership.
Increased Assured . 725 MW added to 800 MW
LTIAP Exhibit B.
Delivery . Additional scenario with
1,525 MW (725 MW + potential
800 MW more). Also looks
at removal of current LTIAP
constraints on contract
type.
Increased Assured . Same as Increased Assured
Delivery except assumes that non-
Delivery --Access for scheduling parties
interested in Capacity Ownership are
Non-Scheduling eligible for Assured
Delivery.
Utilities

(Table 4-1 continues on
next page)

Summary of NFP eis Alternatives

Economic Priority . Non-Federal access must
meet contract-specific economic
benefit test to be
applied by BPA.
. Two generic contract
scenarios: seasonal exchanges, firm
power sales.

BPA Intertie Marketing Alternatives
Federal Marketing & . Assumes new BPA contracts
to increase value of hydro fish
Joint Ventures operations.
. New contracts would use
hydro flows for fish. Contracts to be

size.

flexible as to type and

studied: (A) 1,100 MW seasonal

. Example generic contracts

power/capacity for fall/winter energy;

exchange of BPA

venture 10-month firm power sale with

(B) 1,100 MW joint

exchange.

2-month power/energy

joint ventures.

. Non-Federal access via

addresses potential contracts up to

. Additional scenario

2,200 MW.

4.1.2 Methods of Analysis

The environmental effects of the alternatives would be a result of either changes in electric power resource operation or changes in resource acquisition. Once resource operation or development changes were quantified in terms of megawatts, environmental impacts were assessed. For existing generating plants, air emissions, land disturbance, wastes, and other potential impacts were based on plant-specific information. For new generating plants, generic information was used regarding the air emissions, land disturbance, wastes, and other effects associated with the relevant type of technology, i.e., gas-fired combustion turbines, wood waste cogeneration, or other resource type.

Changes in resource operation were assessed via several modeling techniques. Briefly, the study tools assess how PNW and Canadian resources are run in context with an assumed PSW market using high and low PNW loads and high gas prices. (See Appendix F on modeling analysis methods and results for this eis.) For the PNW, the study results identified specific PNW resources that would be expected to generate more or less under the alternatives. This plant-specific data was produced for the PNW hydro system and for thermal plants. For PSW and ISW resource operations, the studies were used to determine the change in net amount of power transferred over the Intertie between the regions. Changes in the pattern of PSW resource operation were based on a combination of quantitative results and qualitative estimates reflecting recent operating experience. California resource operation changes are treated by class of resource rather than specific plants. Changes in west coast resource acquisition were assessed primarily by reference to official planning and regulatory processes in both regions (see Chapter 2) and the resource plans of individual entities where available. The types of resources and the amounts of generation expected were used to assess changes in impacts to the environment.

A brief comment is needed regarding the difference between the study horizon (20 years) and the possible timeframes of action (possibly 35 years). The actions being considered in this eis could result in commitments as long as 35 years, while the modeled studies and major planning documents cover 10 to 20 years. Whether the 20-year analysis of impacts is a good estimate for the 35-year horizon

depends on the uncertainty that key factors will remain consistent in the 21st year onward with the assumptions used here. It would be especially important to identify uncertainties that would result in an understatement of impacts. The problem of future uncertainty has been approached for this analysis in two ways:

(1) Low, medium, and high PNW load forecasts were used to increase the chance that actual effects would be within the ranges studied.

(2) Resource development for the alternatives is brought on within the 20-year horizon using the resource stacks based on current conservation and power production technology. Since the trends in new resource technology are in the direction of minimizing environmental impacts of power production, this analysis should err in the direction of overstating long-term impacts.

Non-Federal access and Federal marketing alternatives were analyzed in the same ways. A combination of modeling and other techniques was used. The Capacity Ownership, Increased Assured Delivery, and Federal Marketing/Joint Ventures alternatives were modeled under contrasting scenarios, assuming the new transactions would either be predominantly seasonal exchange or firm power sales. (Increased Assured Delivery with Intertie Access for Non-Scheduling Utilities was not separately modeled because the entity-specific features of this alternative did not lead to different assumptions as to resources built or used or contracts entered into. The Economic Priority alternative was not separately modeled because its impacts were considered to be adequately represented by the other seasonal exchange cases. The impacts of these alternatives would be reasonably represented by the Capacity Ownership and Federal Marketing/Joint Venture cases.)

4.1.3 Overview of Results

Environmental Effects of Non-Federal Intertie Access Alternatives

1. Effects of Increased Non-Federal Autonomy. The non-Federal access alternatives

differ from each other principally in the degree of autonomy and related business certainty they present to the parties. The differences in autonomy and business certainty may increase the probability of long-term firm transactions and new resource development, but the increased probability is not quantifiable. Differences in non-Federal autonomy would not change the west coast market influences which affect the desirability of seasonal exchanges, power sales, or other types of contracts. It should be noted that the removal of market obstacles assumed for the Capacity Ownership alternative may be the law of the land under the transmission access provisions of Section 721 of the 1992 Energy Policy Act.

2. Type of Contract. Whether Intertie contracts were predominantly seasonal exchange or firm power sale did produce environmental differences for both regions, as described below for marketing alternatives. The preferred alternative, Capacity Ownership, includes the greatest degree of utility flexibility of use and autonomy and therefore less business uncertainty for proposed transactions. Capacity Ownership might therefore result in more firm contracts of any type compared to No Action, Assured Delivery, or Economic Priority, but not by a quantifiable amount. Information on proposed transactions indicated that a mix of seasonal exchange and power sales contracts would be likely. Hypothetical new resource development cases were reviewed to provide information on maximum effects. PNW or Canadian parties may have incentive to add resources to serve PSW contracts. Utilities may advance their resource stacks, resulting in added conservation and renewable resources as well as thermal

generation. Some utilities and independent power producers may also plan resource additions largely for export. The increased PNW thermal additions would be larger than projected PNW thermal resource development under expected loads.

3. Operation and Development of Resources. The impact analysis for non-Federal Intertie access alternatives did not reveal significant differences among the alternatives except to the extent that the features of the alternatives influenced the assumed mix of Intertie contract types. These impacts are described below under Environmental Effects of Marketing Alternatives.

4. Other Issues. The Capacity Ownership alternative may require decisions allocating the

available capacity among requesters. The allocation variations studied did not cause significant environmental changes. The Capacity Ownership alternative also incorporates a BPA policy on PNW Power Act Section 9(c) addressing a utility's ability to request future additions to its requirements service in view of resource exports outside the region. This policy was found to have no significant environmental effects in that BPA resource acquisitions would be unchanged.

Environmental Effects of Marketing Alternatives

The Federal Marketing and Joint Ventures alternative showed potential to produce some operational and environmental differences compared to No Action due to seasonal operations and resource development. This would apply equally to non-Federal access alternatives to the extent they may result in similar types of contracts. The No Action case with respect to Federal marketing and joint ventures consists of existing Intertie long term contracts and projected long term nonfirm marketing. The impacts associated with Federal marketing or non-Federal access were strongly affected by the assumed predominant contract type -- seasonal exchange or firm power sale. The impacts were in two categories:

(1) seasonal resource operations changes due to coordination, and
(2) resource acquisition changes.

1. Seasonal Resource Operations and Environmental Effects. The potential operation changes due to increased seasonal coordination between the PNW and PSW were variable and sensitive to assumed loads and hydro conditions. Resulting air emissions, for example, could increase or decrease for the same alternative as assumed loads and hydro conditions were varied. The operations changes were generally small in magnitude whether positive or negative (except in cases of high new resource acquisition addressed in connection with firm power sales below). Under seasonal exchange contract scenarios for any non-Federal access or BPA marketing alternative, PNW annual average generation of all resource types tended to decrease slightly. Firming the May-June assumed fish flows shifted a small amount of PNW thermal generation from winter to May and June, as would be expected. Analysis of generic contracts showed that annual average net amounts taken by PSW from the PNW decreased, increasing net annual PSW generation and therefore air emissions somewhat and shaping some generation from summer to

fall/winter. However, experience with actual shorter term exchange contracts indicated that the seasonal shaping of generation may reduce overall annual nitrogen oxides (NOx) emissions despite the increase in annual generation by use of plants with lower NOx emission rates. Seasonal exchanges may defer some PNW thermal resource acquisitions in the long run, such as gas-fired combustion turbines to support winter service. Deferral of thermal resource construction in the PSW is also possible and, to some degree, is already incorporated into California resource planning

processes. Seasonal exchanges are associated with the environmental benefit of increased Columbia River anadromous fish passage facilitated by increased spring flows.

2. Air Impacts Under Firm Power Sales. Under firm power sales scenarios for any alternative, PNW emission of criteria air pollutants and other impacts of power generation increase somewhat due to addition of new resources to provide the firm power. The seriousness of environmental impacts and health significance of the new emissions is dependent on siting. The increased PNW air emissions would be associated with displacement of PSW emissions. PSW air quality effects would be small compared to total California air emissions, and the overall impact would be positive.

3. Coordinated Seasonal Operations. Combining modeling results with qualitative assessment based on past contract data, the analysis supported a view that some mutual PNW and PSW environmental benefits can be achieved by more coordinated seasonal operations. It is possible, within economic constraints, to design seasonal exchanges that reduce both California summer emissions and total California annual emissions while reducing PNW annual thermal generation. Seasonal exchanges could also be designed which reduce California summer emissions, though increasing total California annual emissions, while reducing PNW thermal generation. Firm power sales would bring about greater reductions in California emissions, but a proportion of the power would come from added thermal generation in the PNW or other regions, including Canada.

4. Resource Acquisition Changes and Environmental Effects. Seasonal exchange scenarios resulted in reduced resource acquisitions by all parties. The resource acquisition effects of hypothetical large power sales cases are potentially significant. The California State regulatory environment would not favor in-State thermal resource additions based on PNW-PSW Intertie

contracts. However, municipal and publicly owned utilities in California are not subject to the same regulation and may have an interest in adding resources for Intertie transactions. As explained for non-Federal access alternatives, above, PNW or Canadian parties may have incentive to add resources to serve PSW contracts. Utilities may advance their resource stacks, resulting in added conservation and renewable resources as well as thermal generation. Some utilities and independent power producers may also plan resource additions largely for export.

Cumulative Environmental Effects of Combined Alternatives

If more than one of the alternatives were adopted simultaneously and if power sales predominated on the Intertie, the development of thermal-type generating resources could be accelerated on the west coast. The effects of accelerated resource development could be of concern, but would only occur if high levels of Intertie firm power sales contracts are assumed to be economically attractive to many parties. Long-term west coast electric power market projections, economic uncertainty, and the risk management strategies of many utilities and utility regulators indicate that Intertie contracts are more likely to be a mix of products, including seasonal exchanges, firm power sales, capacity and other services, and economy sales. This mix of contracts would not be likely to result in a great acceleration of new resource development.

Since resource development is a key environmental concern, a large hypothetical power sales export case was constructed to display a likely upper bound. This large hypothetical case assumed adoption of the Capacity Ownership alternative for 725 MW, the Federal Marketing and Joint Ventures alternative, and other possible access expansions (additional Capacity Ownership or Increased Assured Delivery for approximately 800 MW). Under this hypothetical case, approximately 2,500 aMW of new resources could be developed for transfer on the Intertie. For the PNW, the maximum combustion turbine and coal plant development would be greater than the maximum cases studied in the Resource Programs eis

for combustion turbine and coal development. PSW new resource development could also increase if transfers to the PNW increased, for example, supplies of winter energy. Gas-fired combustion turbines would appear to be the resource type of choice. Increased west coast thermal resource additions could have environmental significance, but site location information would be needed to assess seriousness.

4.2 Background Factors Affecting the Impacts

1. Factors outside the alternatives studied here have a large influence on the environmental impacts of West Coast electric power operations, sometimes far outweighing that of the alternatives. Weather-related water availability, economic and other trends affecting electric load growth, and the price of natural gas change electric power generation more than the alternatives studied here, therefore resulting in greater impacts on the environment.

2. The No Action alternative includes an Intertie market which is quite active and open on a short-term economic basis. The alternatives studied here are compared to a No Action alternative that assumes a very active and open economy energy market using the Intertie. The size of the Intertie is large enough for most available PNW export power. Parties with access are using the Intertie for economic transactions that achieve at least some of the environmental benefits of cooperation between the two regions. To some degree, the transactions proposed under the alternatives are simply long-term agreements to secure some of the benefits achieved on a non-firm basis with economy energy. Long-term firm transactions have the added advantage of allowing predictable operational displacement and deferral of resource acquisitions.

3. Nationwide law and policy on transmission access is changing. Transmission access reform to the Federal Power Act (as contained in Title VII Section 721 of the Energy Policy Act of 1992) gives the FERC the authority to order transmission access to be provided to requesting entities by utilities that own transmission lines. This would tend to decrease the real differences between No Action and any of the alternatives with respect to the increased development of new resources and associated environmental impacts.

4.3 PNW Effects

4.3.1 PNW Resources Run and Displaced

Analysis of PNW resource operation changes is supported by materials in Appendix F. Part 4 of Appendix F, "PNW Resource Operation Results," is a detailed description of the results, including data tables. The non-Federal access alternatives did not result in significantly different resource operation patterns. Operational changes of a small degree were associated with the type of generic contracts assumed -- seasonal exchange or firm power sale. The Federal Marketing and Joint Venture alternative resulted in some relatively small changes in pattern of resource operations, depending on the generic contract type assumed. As described above, the Capacity Ownership and Federal Marketing/Joint Venture alternatives were assumed for modeling purposes to have two possible contract type scenarios, seasonal exchange or power sale, to bracket the extremes within which the eventual mix of negotiated contracts might fall. The Economic Priority alternative was not separately modeled but is expected to facilitate seasonal exchanges or power sales equally. Its effects would be similar to Capacity Ownership or Federal Marketing and Joint Ventures.

The seasonal exchange scenarios modeled would apply to Capacity Ownership, Federal Marketing and Joint Ventures, and Economic Priority. For these, annual PNW resource operation changes were as follows:

1. PNW annual hydro operations changes were negligible. They varied within the range of -6 aMW to +7 aMW, under high PNW load assumptions. These MW amounts were less than 0.1 percent of base case/No Action alternative hydro generation. Under low PNW loads, hydro changes ranged from -13 to -34 aMW.
2. PNW coal generation changes were also negligible. Under high loads, coal generation changed between 0 and -19 aMW; all changes were less than 0.3 percent of base case generation. Under low loads, coal generation decreased between -15 and -79 aMW.
3. PNW CT generation generally decreased by small amounts. Under high loads, CT generation changed between -12 and -128 aMW, percent differences of 0.5 percent to 5.7 percent from base case generation. Under low loads, CT generation ranged from an increase of 9 aMW to a decrease of -22 aMW.

Study results for the firm power sales scenarios are given below. Results are presented separately for the Capacity Ownership and Federal Marketing/Joint Venture cases because the studies treated them differently as to the assumed source of non-Federal power. Briefly, because of some assumptions described in detail below, the Capacity Ownership results appear to have less displacement of PNW thermal resources than the Federal Marketing and Joint Venture alternative; however, this is not due to the features of the Capacity Ownership concept.

The Federal Marketing and Joint Venture alternative may involve joint venture resources from inside or outside the PNW region. In order to keep the results neutral as to the source of power, the joint venture power was not modeled as coming from a particular party. In addition, to reflect possible joint venture arrangements, the joint venture power was modeled as not displaceable. Capacity Ownership power sales contracts were assumed to be served by new PNW non-BPA resources with economic displacement taking place whenever possible. Federal Marketing/Joint Venture power sales were assumed to be served by a new generic resource from a non-specified source that was treated as non-displaceable and costed like a new combined cycle combustion turbine. Because this new resource is not supplied by a PNW party and is assumed to be non-displaceable, the results from the Federal Marketing and Joint Venture cases show reduced generation for other types of PNW resources, compared to Capacity Ownership. The Capacity Ownership proposal itself does not produce less thermal displacement. Actual transactions under Capacity Ownership or Federal Marketing and Joint Ventures could look like a blend of these two cases, with firm power being supplied from sources that have contractually negotiated displaceability.

The resource operation changes for Capacity Ownership power sales cases were as follows:

1. PNW annual hydro generation changes were negligible. Hydro generation changed by roughly 5 aMW under high loads, which was less than 0.1 percent of No Action generation under high loads. Under low loads, hydro generation decreased by approximately -64 aMW, which was about 0.4 percent of No Action generation under low loads.
2. PNW coal generation changes were also negligible. Coal generation changed between +6 aMW under high loads and -22 aMW under low loads. The percent changes were less than 1 percent of No Action generation under either high or low loads.
3. PNW CT generation increased between 454 aMW, or 20 percent of No Action generation, under high loads and 311 aMW, or 184 percent, under low loads. This reflects increased operation of CTs, which had been acquired to meet PNW load growth. See Section 4.3.3, page 4-11, for analysis of resource acquisitions.

The resource operation changes for Federal Marketing/Joint Venture power sales cases were as follows:

1. PNW annual hydro generation essentially did not change under high loads. Under low loads, hydro generation decreased by approximately -167 aMW, or 0.1 percent of base generation.
2. PNW coal generation under high loads decreased between -58 aMW, or 1.2 percent, under high

loads to -174 aMW, or approximately 5 percent, under low loads.

3. PNW CT generation data from the modeling analysis showed decreases, but this data does not include the expected generation from new joint venture resources, covered under point 4 below. Under high loads, CT generation declined -130 aMW, or approximately 6 percent. Under low loads, No Action case CT generation was 169 aMW and was reduced under the alternative to -30 aMW, or 22 percent.
4. Estimated generation for the new joint venture resource(s) must be added to the data in the Appendix F tables. For the assumed 1,100 MW example generic contract, 917 aMW is estimated to be supplied from new resources. The amount of joint venture resource generation could be more or less, depending on the specific contract provisions.

Cumulative effects were examined for mixed cases combining generic seasonal exchanges and generic power sales with both the Capacity Ownership and Federal Marketing and Joint Ventures alternatives in place. The effects of mixed contract-type cases are of interest because market data indicates that the likely real transactions would be a diverse mix of contract types. Cumulative cases combining two alternatives both in power sale mode are discussed in Section 4.3.3, page 4-11, in connection with maximum PNW thermal resource effects. These are of interest because they show the likely upper bounds of resource development effect. Mixed combined cases produced resource operations results as follows:

1. PNW annual hydro generation did not change under high loads for any case. Under low loads, hydro generation decreased for all cases but no change was greater than 0.1 percent of base generation.
2. PNW coal generation under high loads decreased by less than 1 percent under high loads for all cases. Under low loads, decreases were seen between barely measurable and 7 percent. The greater coal displacements were seen when the Federal Marketing/Joint Venture power sales case was combined with Capacity Ownership seasonal exchanges. This reflects the assumption that the resource supporting the Federal Marketing/Joint Venture contract was nondisplaceable and ran to displace PNW coal.
3. PNW CT generation changes were consistent with the results for the single power sale cases. Under Federal Marketing/Joint Venture cases, the assumed nondisplaceable source of supply would displace PNW CTs. Under the Capacity Ownership cases, the assumed newly acquired combustion turbines operate to show increased CT generation.

The Federal Marketing and Joint Venture alternative contained exchange energy to be returned to the PNW in both the power sales and seasonal exchange scenarios. Therefore, there was an overall annual decrease in PNW generation in both cases -- larger under the generic seasonal exchange, and smaller under the joint venture power sale/exchange combination. There was also a small shift of PNW thermal generation from the fall and winter months to May and June, when the largest firm contract transfers to the PSW were planned. This is consistent with the way the study methodology viewed the effect of the alternative on the PSW market, i.e., the contract resulted in an increase in total deliveries to the PSW,

firm and economy energy, in those months, making some additional PNW thermal resource operation economic. The discussion in Appendix F, Part 4, explains this more fully. This shift of thermal generation among months of the year would also be reasonable since flows for fish will be dispatched in pulses for fish benefit and may not be dispatchable for power use. This may require available PNW thermal generation to be dedicated at times to firm up the contract delivery.

4.3.2 PNW Resources Acquired and Deferred

This section deals with the aggregate environmental effects of potential PNW resource acquisition. The site-specific effects of conservation programs or generating resources acquired by BPA, eligible for billing credits by BPA, or electrically integrated and transmitted by BPA, would be covered by their own environmental reviews. PNW resource acquisition effects were analyzed in two ways:

1. For modeled cases, the stacks of resources needed to serve the assumed loads under the alternatives were compared to the No Action case. Expected BPA and IOU resource additions were described for 20 years under low, medium, and high loads. These are shown in Appendix F, Part 2, "NFP eis Analytical Specification." This showed no new resource additions or deferrals due to the alternatives. Some resources that had been acquired to serve regional loads showed increased generation under the alternatives.

2. Further analysis was done of resource acquisitions or deferral that would not be shown by the modeling data. This analysis used information from BPA's 1992 Resource Program, BPA's 1992 Pacific Northwest Loads and Resources Study, and other publicly available information on planned resources that might be available for export. This analysis addressed:

- unspecified new resources used under the Federal Marketing and Joint Ventures alternative in its power sale mode;
- Resource deferrals due to increased PNW-PSW coordinated operation;
- new resources which might be acquired under scenarios with more MWs non-Federal access than the example cases under the alternatives, such as Capacity Ownership for more than 725 MW; and
- resource acquisitions under various possible BPA policies on PNW Power Act Sections 9(c) and (d).

For the non-Federal access alternatives under the seasonal exchange scenarios and for the seasonal exchange portions of the Federal Marketing and Joint Venture alternative the exchange energy was assumed to produce a PNW energy surplus as opposed to resource deferral, which was shaped into the fall and winter months to serve a market when energy would be returned from the PSW. The largest incremental surplus was associated with the Federal Marketing Case A and was approximately 160 aMW. The smallest was associated with the Federal Marketing Case B and was approximately 39 aMW. Though these studies did not use the incremental surpluses specifically to defer new resource investment, this is a choice that could be made. It is also possible that exchange energy could defer new resource costs even in years in which the PNW was not deficit on an annual energy basis. A PNW energy or capacity deficit in a single month or season could require an acquisition to be made, such as a contract purchase or, for a long-term deficit, the addition of a combustion turbine. Firm energy deficits within months or seasons are increasingly possible in view of new hydro operating limits that affect PNW ability to use storage to shift hydro generation among months of a year.

The major change in PNW resource acquisition was seen with firm power sales scenarios for any non-Federal access or marketing alternative. For all alternatives, firm power sales contracts would require

new resource acquisition or the advancement of resources planned for future PNW load growth. A very large-sized power sales export scenario might assume adoption of both BPA preferred alternatives (non-Federal access via Capacity Ownership of 725 MW combined with Increased Assured Delivery -- Access for Non-Scheduling Utilities, and Federal Marketing and Joint Ventures) and other possible Intertie access expansions. For example, given the recommendations of some outside parties, incremental Capacity Ownership could be extended to the full 1,450 MW capacity gained by BPA from the Third AC project. Also for example, a revised LTIAP responding to the Energy Policy Act of 1992 could increase non-Federal access. In addition, the amount of Federal Marketing and Joint Ventures needed to deal with flows for fish could be larger than the 1,100 MW example studied. A hypothetical cumulative scenario could add approximately 2,500 aMW Intertie access for new resources. The questions would be: how big is this 2,500 aMW scenario in relation to the otherwise-projected PNW need for resources, and what resource types would be developed?

The incremental 2,500 aMW new resource development can be put in context by comparison to current projections of the PNW need for resources. BPA and other PNW need for resources is a function of assumed load factor. Table 4-2 shows BPA and PNW planning deficits under three load forecasts -- high, medium high, and medium. BPA's 1992 Resource Program plans to acquire 600 aMW of cost-effective conservation, 120 aMW of efficiency improvements, and 400 aMW of other resources to meet the medium-high forecast (within a 10-year horizon) and to acquire 250 aMW of options to cover up to the high load forecast.

Table 4-2 BPA and PNW Load/Resource Balance (1992 Pacific Northwest Loads and Resources Study)

Average Megawatts

	BPA		PNW Region (BPA and other utilities)	
	2003	2013	2003	2013
Medium	-886	-1,829	-3,425	-5,626
Medium- high	-1,974	-3,443	-5,347	-8,948
High	-3,189	-5,608	-8,278	-14,040

The resource types expected to be acquired would be a mix of conservation programs, renewable resources, combined cycle gas-fired combustion turbines, and cogeneration and other thermal resources, based on BPA's Resource Programs eis Record of Decision. The resource plans of parties interested in capacity ownership indicate interest in combustion turbines and biomass cogeneration projects.

For the 2,500 aMW hypothetical cumulative scenario mentioned above, the effect on the regional resource mix can be estimated from the differences between the BPA and IOU resource stacks for medium or high loads, which were developed using the ISAAC model for the alternatives studied here.

The data on types of resources in the stacks is consistent with the latest Resource Program data. The differences in resource additions for the high versus medium load forecasts provide a reasonable view of the types of resources that would be added or advanced for the hypothetical cumulative 2,500 aMW incremental scenario. The comparisons described here refer to the BPA and IOU resource additions in Tables 1 through 4 of Appendix F, Part 2.

IOU resource additions under high loads differ from the medium load additions as follows:

- conservation by 2012 increased from 1,361 aMW to 1,727 aMW;
- renewable resources increased from 2,066 aMW to 3,733 aMW;
- combined cycle CT acquisitions of 1,095 aMW were not changed; and
- new coal additions were advanced by 7 years and increased from 426 aMW to 3,408 aMW.

BPA resource additions changed as follows:

- conservation by 2012 increased from 1,097 aMW to 1,397 aMW;
- renewable resources increased from 440 aMW to 1,026 aMW;
- combined cycle CTs increased from 365 aMW to 2,190 aMW;
- no coal resources were acquired under either load forecast; and
- WNP-3 (806 aMW) was added in 2004 under high loads and was not added under medium loads.

In view of the uncertainty of WNP-3, BPA's resource acquisitions might include coal plants. Also, to the extent that the new resource development was due to independent power producers, there might be greater emphasis on combustion turbines, renewable resources, and cogeneration projects.

As mentioned in the Chapter 3 description of the Capacity Ownership alternative, BPA has proposed a Northwest Act Section 9(c) policy determination for non-Federal participation. This policy determination addresses whether the export of non-Federal resources would affect a utility's right to request future additions to its firm requirements service from BPA. BPA's 1992 Resource Program data and assumptions were reviewed to see if non-Federal access and assumed non-Federal Intertie contracts would affect BPA's need to acquire resources. This review concluded that BPA's resource acquisition obligations would be unchanged under the proposal.

4.3.3 PNW Environmental Effects

4.3.3.1 PNW Thermal Resources Effects

Thermal resource environmental impacts appeared to be only those due to the addition of new plants because operation of existing PNW thermal plants would not be affected by the alternatives. Increases in air pollutants, water quality impacts, land effects, wastes, and employment safety and health effects are summarized in Tables 4-3 through 4-6. The effects range from none to potentially large relative to already-planned resource additions. Effects increase to the extent that it is assumed that new resources are added and this is linked to the predominance of firm power sales over seasonal exchanges. Actual environmental impacts would not be quantifiable, nor could they be assigned to specific geographical locations in advance of actual agreements defining the obligations of specific parties.

The following analysis of impacts uses data and methodology from BPA's Resource Programs Final eis, which describes the environmental impacts associated with the development and operation of a wide variety of potential new resources. This information has been reproduced as Appendix E to this eis.

Resources added due to the NFP eis alternatives are expected to be primarily combined-cycle, gas-fired combustion turbine plants in either cogeneration or purely generation configurations, or wood-waste-fired cogeneration. Cogeneration resources and their environmental effects are discussed in Appendix E, Section 3.2.2.1. Combined cycle combustion turbine resources and their environmental effects are discussed in Appendix E, Section 3.2.2.2.

Information provided by potential Intertie capacity owners indicates that the mix of new gas-fired combustion turbine resources and new wood waste-fired cogeneration is expected to be about 80 percent of the former and 20 percent of the latter. The following tables show the environmental impacts for the high and low estimates of new thermal resource additions, given this assumed 80:20 ratio.

Tables 4-3 through 4-6, below, use the methodology from the Resource Programs eis Tables 3-24 and 3-26 (see Appendix E), which show environmental impacts per average annual MW electric energy generation for a wood waste-fired facility and a combined cycle CT facility, respectively. The methodology used here assumes all the energy input into the facilities is used to produce electricity. This may result in some understatement of the impacts per average annual MW of cogeneration facilities where only a portion of the energy input produces electricity. On the other hand, the overall impacts of a cogeneration facility are generally less than those of separate facilities providing for

electric generation and another process or heating energy needs. Many of the impacts of the CT and cogeneration resources assumed to be developed for export, as with impacts of all types of development, will be highly site-dependent. The seriousness of air emission effects on health, socio-economics, or aesthetics cannot be judged on a generic regional basis. However, global warming concerns due to CO2 increases are not site-dependent. Also, magnitudes of land and water impacts from fuel procurement can be estimated without knowing the generating resource site.
BPA's Resource Programs Final eis noted that smaller generating facilities such as CTs and cogeneration tend to be located nearer to populated areas than large generating stations. For air quality modeling purposes, the Resource Programs eis assumed that new CTs are located in western Washington except for the Emphasize CT alternative, in which the new CTs were split between western and eastern Washington. New natural gas-fired cogeneration is assumed to be located in western Washington and eastern Oregon. Portions of western Washington have experienced nonattainment for some airborne pollutants of types expected from CT's or cogeneration facilities, but site-specific analysis would be necessary to assess impacts.
Eastern Oregon has not experienced nonattainment for air pollutants, but some areas would be sensitive to visibility concerns, land and water disturbance, and other site-specific concerns.

Table 4-3 Maximum Annual Environmental Impacts From Added Natural Gas-Fired Combined Cycle Combustion Turbine Resourcesa 1,078.4 aMW Combined Cycle CT Resources

```
  Potential Impacts                               On-Shore Gas
Transportation          Generation
                                                  Extraction
------------------------------------------------------------------------------
----------------------------
Air Pollutants
Sulfur Oxides (tons)                               1024
0.432 tons           32.4d
Oxides of Nitrogen (tons)                          60.4
6270d
Particulates (tons)                                1.40
32.4d
Carbon Dioxide (tons)
4.21 x 10E6d
 Carbon Monoxide (tons)
2.41 x 10E3e
------------------------------------------------------------------------------
----------------------------
Water Quality Impacts
Consumption (acre-ft)
3670f
```

Discharge (acre-ft)   6.26 acre-ft drilling /mud
8.74
Biological Oxygen Demand (tons)   1.19
702
Chemical Oxygen Demand (tons)   7.98
Oil and Grease (tons)   24.6
Chromium (tons)   0.0647
Zinc (tons)   0.0216
Total Dissolved Solids   329
1143
(tons)
Total Suspended Solids (tons)
1230
Ammonia (tons)
0.129
Chloride (tons)   61.5
Sulfate (tons)   49.6

Thermal Discharge
3.11 x 10E7
mmBtu

Land Effects b   27.0 Permanent   4510
219
Acreage Requirements   34.5 Temporary

Waste Streams
Solid Wastes (tons)   2420 (Drill Cuttings)
undetermined

Employment b
Construction (employee-   31.3   485
1510
years)
Operations (employees per   3.24   14.0
employees   108
year)

Occupational Safety and
Health   c
O&M Injuries   8.30 x 10E-5 to 2.34 x 10E-3 1.14 x 10E-4
to 1.83 x 10E-4 3.67 x 10E-3 to 6.84 x 10E-2
O&M Deaths   9.71 x 10E-7 to 2.41 x 10E-5 3.24 x 10E-7
to 3.24 x 10E-6 2.70 x 10E-5 to 1.19 x 10E-3
Construction Injuries
7.33 x 10E-3 to 1.07 x 10E-1
Construction Deaths
2.41 x 10E-5 to 4.31 x 10E-4

a Cumulative Case Federal Marketing B with Capacity Ownership Power Sales (HHFMBCO5PS). Unless otherwise indicated,

these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.
b See sources and calculations in Appendix F to the Resource Programs eis. Sixty-five percent capacity factor assumed.
c Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California. Generation estimates for a natural gas fuel cell.
d From BPA's emission estimates for environmental costs and planning.
e Adapted from Northwest Power Planning Council. 1991. Northwest Conservation and Electric Power Plan, Volume II-Part II.
f Flow rate requirements taken from Fluor Daniel, Inc. 1988. Development of Combustion Turbine Capital and Operating Costs. DOE/BP-63056-1. Bonneville Power Administration, Portland, Oregon.

Table 4-4 Maximum Annual Environmental Impacts From Added Wood Waste-Fired Resources a 269.6 aMW of Wood Waste- Fired Cogeneration

```
Potential Impacts               Mining and Processing      Transportation
Generation
------------------------------------------------------------------------------
---------------------------
Air Pollutants
Sulfur Oxides (tons)            Fossil-fueled equipment       Transport by
truck or              154  f
Oxides of Nitrogen (tons)       will release pollutants.      train will
result in              2680  f
Particulates (tons)             Reduced slash burning         pollutants from
fossil            507  f
Carbon Dioxide (tons)           will improve air quality in   fuels.
3.55 x 10E6f
Carbon Monoxide (tons)          forests.
5040  f
Thermal Discharge (tons)
1.39 x 10E7  b

------------------------------------------------------------------------------
---------------------------
Water Quality Impacts           Forest harvest may
Consumption  (acre-ft)          contribute to erosion.
14640
General Effluent (acre-ft)
7740

------------------------------------------------------------------------------
---------------------------
Thermal Discharge
Varies significantly
Land Effectsc                   478,500 acres of 70-year-old
Acreage Requirements            forest needed per year to
960

                                supply 25% of fuel needs;
                                potential loss of wildlife habitat
                                and up to 3.37 x 107 pounds of
                                nitrogen from soil.e
```

Waste Streams 75% of fuel expected from
29100
Solid Wastes (tons) mill wastes.d

Employment c
Construction (employee-years
3500
per MW capacity)
Operations (employees per
1640a
MW capacity)

Occupational Safety and
Healthd
O&M Injuries 8.69 x 10E-2 1.08x 0E-4 to 7.01x10E-4 1.62 x 10E-4 to 5.39 x 10E-4
O&M Deaths 5.39 x 10E-4 0 to 4.04 x 10E-7
1.46 x. 10E-6 to 1.21 x 10E-5
Construction Injuries
4.31 x 10E-5 to 1.21 x 10E-3
Construction Deaths
8.09 x 10E-7 to 4.58 x 10E-6

a Cumulative case Federal marketing B with Capacity Ownership Power Sales (HHFMBCO5PS). Unless otherwise indicated, these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.

b Flue gas.

c See sources and calculations in Appendix F to the Resource Programs eis. Eighty percent capacity factor assumed.

d Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California.

e Adapted from ECO Northwest, Ltd., Shapiro and Associates, Inc., and Seton, Johnson, and Odell, Inc. 1986. Estimating Environmental Costs and Benefits for Five Generating Plants. DOE/BP-11551-2. Bonneville Power Administration, Portland, Oregon.

f Adapted from Northwest Power Planning Council. 1991. Northwest Conservation and Electric Power Plan, Volume II, Part II, Portland, Oregon.

Table 4-5 Minimum Annual Environmental Impacts From Added Natural Gas-Fired Combined Cycle Combustion Turbine Resourcesa 0213.6 aMW of Natural Gas-Fired CT Resources

Potential Impacts On-Shore Gas Transportation
Generation
Extraction

```
-------------------------------------------------------------------------------
------------------------
Air Pollutants
Sulfur Oxides (tons)               203                          0.0854
6.41  d
Oxides of Nitrogen (tons)          12.0                         56.8
1240  d
Particulates (tons)                0.278
6.41  d
Carbon Dioxide (tons)
8.34 x 10E5  d
 Carbon Monoxide (tons)
476  e
-------------------------------------------------------------------------------
------------------------
Water Quality Impacts
Consumption (acre-ft)
726   f
Discharge (acre-ft)                1.24 acre-ft drilling /mud
1.73
Biological Oxygen Demand (tons)    0.235
Chemical Oxygen Demand (tons)      1.58
139
Oil and Grease (tons)              4.87
Chromium (tons)                    0.0128
Zinc (tons)                        0.00427
Total Dissolved Solids             65.2
226
(tons)
Total Suspended Solids (tons)
243
Ammonia (tons)
0.0256
Chloride (tons)                    12.2
Sulfate (tons)                     9.83
-------------------------------------------------------------------------------
------------------------
Thermal Discharge
6.15 x 10E6
mmBtu
-------------------------------------------------------------------------------
------------------------
Land Effectsb                      5.34 Permanent               893
87.0
Acreage Requirements               6.84 Temporary
-------------------------------------------------------------------------------
------------------------
Waste Streams
Solid Wastes (tons)                478 (Drill Cuttings)
undetermined
-------------------------------------------------------------------------------
------------------------
Employmentb
Construction (employee-            6.19                         96.1
812
years)
```

Operations (employees per   0.641   2.78 employees
58.0
year)

Occupational Safety and
Healthc
O&M Injuries   1.64 x 10E-5 to 4.64 x 10E-4   2.26 x 10E-5 to
3.63 x 10E-5 7.26 x 10E-4 to 1.35 x 10E-2
O&M Deaths   1.92 x 10E-7 to 4.76 x 10E-6   6.41 x 10E-8 to
6.41 x 10E-7 5.34 x 10E-6 to 2.35 x 10E-4
Construction Injuries
1.45 x 10E-3 to 2.11 x 10E-2
Construction Deaths
4.76 x 10E-6 to 8.55 x 10E-5

a Cumulative case with Federal Marketing and Capacity Ownership seasonal exchange (LHFMACO1PS). Unless otherwise indicated, these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.
b See sources and calculations in Appendix F to the Resource Programs eis. Sixty-five percent capacity factor assumed.
c Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California. Generation estimates for a natural gas fuel cell.
d From BPA's emission estimates for environmental costs and planning.
e Adapted from Northwest Power Planning Council. 1991. Northwest Conservation and Electric Power Plan, Volume II-Part II.
f Flow rate requirements taken from Fluor Daniel, Inc. 1988. Development of Combustion Turbine Capital and Operating Costs. DOE/BP-63056-1. Bonneville Power Administration, Portland, Oregon.

Table 4-6 Minimum Annual Environmental Impacts From Added Wood Waste-Fired Resourcesa 53.4 aMW of Wood Waste- Fired Cogeneration

Potential Impacts   Mining and Processing   Transportation
Generation

Air Pollutants
Sulfur Oxides (tons)   Fossil-fueled equipment   Transport
by truck   30.4f
Oxides of Nitrogen (tons)   will release pollutants.   or train
will result in   531f
Particulates (tons)   Reduced slash burning will   pollutants
from   100f
Carbon Dioxide (tons)   improve air quality in   fossil
fuels.   7.04 x 105f
Carbon Monoxide (tons)   forests.
999f
Thermal Discharge (tons)
2.76 x 106b

Water Quality Impacts   Forest harvest may

Consumption (acre-ft) contribute to erosion.
2900
General Effluent (acre-ft)
1530

Thermal Discharge
Varies significantly

Land Effectsc 94,800 acres of 70-year-old
Acreage Requirements forest needed per year to supply
381

25% of fuel needs; potential
loss of wildlife habitat and up to
6.68 x 106 pounds of nitrogen
from soil.e

Waste Streams 75% of fuel expected from mill
5770
Solid Wastes (tons) wastesd

Employmentc
Construction (employee-years per
1390
MW capacity)
Operations (employees per MW
653a
capacity)

Occupational Safety and Health
d
O&M Injuries 1.72 x 10E-2 2.14 x 10E-5 to
1.39 x 10E-4 3.20 x 10E-5 to 1.07 x 10E-4
O&M Deaths 1.07 x 10E-4
2.88 x. 10E-7 to 2.40 x 10E-6
Construction Injuries 0 to 8.01 x 10E-
8 8.54 x 10E-6 to 2.40 x 10E-4
Construction Deaths
1.60 x 10E-7 to 9.08 x 10E-7

a Cumulative case Federal Marketing A and Capacity Ownership seasonal exchange (LHFMACO1PS). Unless
otherwise indicated, these generic estimates are adapted from: U.S. DOE. 1983. Energy Technology
Characterizations Handbook, Environmental Pollution and Control Factors. DOE/EP-0093. Washington, DC.
b Flue gas.
c See sources and calculations in Appendix F to the Resource Programs eis. Eighty percent capacity factor
assumed.
d Adapted from Arthur D. Little. 1985. Analysis of Routine Occupational Risks Associated with Selected

Electrical Energy Systems. ea-4020. Electric Power Research Institute, Palo Alto, California.
e Adapted from ECO Northwest, Ltd., Shapiro and Associates, Inc., and Seton, Johnson, and Odell, Inc. 1986.
Estimating Environmental Costs and Benefits for Five Generating Plants. DOE/BP-11551-2. Bonneville Power Administration, Portland, Oregon.
f Adapted from Northwest Power Planning Council. 1991. Northwest Conservation and Electric Power Plan, Volume II, Part II, Portland, Oregon.

The incremental emissions found for the high case shown in the tables above can be compared to the projected PNW emissions found in BPA's Resource Programs Final eis. This eis summarized PNW regional total emissions from electric power plants for NOx, SO2, TSP, and CO2. These are found in Figures 5-9 though 5-12 of that eis. Table 4-7, below, shows the high case emissions from NFP eis studies as percentages of the regional totals projected for the Resource Programs eis.

Table 4-7 NFP Incremental Combustion Turbine/Cogeneration Emissions as a Percent of PNW Projected Totals

Air Pollutant	NFP emission (tons/year) 1/	1991 2/	2000 2/	2010 2/
NOx	8950.0	15%	9%	6%
SO2	186.4	- - 3/	- - 3/	- - 3/
TSP	539.4	18%	10%	7%
CO2	7.76 x 10E6	35%	18%	11%

1/ From Tables 4-3 and 4-4 above for maximum combustion turbine cases. These cases do not take into account the potential for new PNW coal resource acquisitions under combined cases of high Intertie power sales and more than 725 MW Capacity Ownership. Emissions for such cases would be consistent with Resource Programs Final eis data for the Emphasize Coal and Emphasize Clean Coal alternatives.
2/ Projected emission totals for these years were taken from the 1992 Resource Programs Final eis, Figures 5-9 through 5-12, which were for electric power generation only.
3/ less than 0.01%

As described in Section 4.3.2, a high resource development cumulative case of 2,500 aMW over the basic alternative assumptions was examined to create an upper bound for purposes of comparison.

These upper bounds were then compared to Resource Programs eis alternatives emphasizing different types of resources. The 2,500 aMW addition tended to advance all resource types somewhat, but two resource types -- coal and combustion turbines -- had potential amounts of new resource development that exceeded those studied in the Resource Programs eis. The largest coal development seen under the high cumulative NFP eis case was nearly double that of either the Emphasize Coal or Emphasize Clean Coal alternatives in the Resource Programs eis. The largest combustion turbine development seen under the high cumulative NFP eis case was likewise nearly double the largest case for gas-fired additions studied in the Resource Programs eis (Emphasize Cogeneration alternative.) Since the environmental impacts would be of the same character as reported in the Resource Programs eis for coal, clean coal technologies, and cogeneration and combined cycle combustion turbines, that analysis is incorporated here by reference. As mentioned previously, the 2,500 aMW new resource development is not based on estimated resource supply. It does not reflect an expectation that resource development to that level would be economic or likely.

4.3.3.2 PNW Hydro Resource Effects

As explained in Chapter 1, this eis does not analyze alternative hydro operation plans because BPA will not be making hydro operation decisions here. The decisions made pursuant to this eis on non-Federal access and BPA Intertie marketing will not prejudice decisions on Columbia and Snake River Federal hydro operations. Hydro operation decisions are made in other forums such as the Endangered

Species Act process and the ongoing System Operation Review eis process. For purposes of the NFP eis, it is assumed that Federal hydro facilities will be operated in accordance with decisions made in those primary forums.

Because the BPA marketing alternative studied here makes use of increased Columbia and Snake River flows for fish, this eis takes note of findings from the Interim Columbia and Snake Rivers Flow Improvement Measures for Salmon Supplemental Environmental Impact Statement of March 1993 (1993 Flow Seis). The increased hydro flow operations, which are a key supply component for the Federal Marketing/Joint Venture alternative, have been studied in the 1993 Flow Seis. The effects of flows on juvenile salmonid downstream survival are hard to separate from the life cycle effects of the yearly hydro operating plan as a whole, and other external measures. The 1993 Flow Seis identified a range of flow measures designed to increase the survival of ESA-listed Snake River spring/summer chinook, fall chinook, and sockeye salmon stocks. Life-cycle fish modeling results indicated that the preferred 1993 hydro flow operating plan, when combined with non-flow actions that are assumed to be effective in future years (i.e., transportation, dam bypass improvements, predator control programs), reverses the downward decline of these ESA-listed chinook salmon populations. Modeling showed that long-term population trends for spring and fall chinook stocks appear to increase significantly, while summer chinook population trends tend to increase more moderately under the 1993 Flow Seis hydro operating plan. Sockeye salmon stocks were not included in the life-cycle modeling analyses, but the ongoing captive broodstock program and spring flow measures that increase spring chinook populations were also assumed to benefit the ESA-listed sockeye populations in the future. Increased flows to endangered salmon species are not without environmental and economic costs, as detailed in the 1993 Flow Seis.

4.4 PSW Effects

4.4.1 PSW Resources Run and Displaced

Modeling analysis showed no substantial changes in the annual amounts of power to be delivered from the PNW to the PSW for any alternative compared to No Action. (Changes in PSW resource operation were estimated using the modeled cases described in Appendix F, Part 4.) This is largely because the No Action alternative includes a very active and open economy energy market using the Intertie. To some degree, the transactions proposed under the alternatives would be simply long-term agreements to firm up some of the benefits already present with economy energy. However, recent experience with short-term environmental exchanges suggests that these agreements could promote greater California resource operation efficiency than would be achieved via the economy energy market under the No Action case. This would probably be due to displacement of less efficient California summer generation in favor of winter generation, and a new contractual focus motivating the parties to maximize both the economic and environmental benefits of such exchanges. Changes could be greater if maximum levels of the alternatives were adopted, such as expanded Capacity Ownership for more than 725 MW, plus Federal Marketing and Joint Venture contracts greater than the examples modeled, plus other increases in non-Federal transmission access such as a revised LTIAP responding to national transmission access law.

No significant environmental effects were found due to changed California thermal resource operations because the changes observed in net annual transfers between the PNW and PSW would be small compared to total Intertie transfers (see Table 4-8 below) and very small in the context of total California state peak loads of 62,615 MW for 1992. (See Chapter 2.) The expected changes are as follows:

1. For seasonal exchange cases, the annual amounts imported by the PSW would decline between -21 and -169 aMW. Decline in import corresponds with increased PSW generation to return energy under the exchanges. A small increase in PSW generation would be expected due to the obligation to replace transmission losses and negotiated exchange energy ratios to compensate the PNW party with additional energy for the summer capacity value of the PNW delivery. Based on data on past environmental exchange contracts, California generation to provide the return energy would probably be greater than the amount of MWs displaced in summer by approximately 20 percent or less, depending on negotiated terms and the actual sources of return energy. Data on BPA's 1992 actual environmental exchanges shows energy deliveries to California parties of nearly 700 aMW between May and August (with capacity) and corresponding energy returns to the PNW of approximately 850 aMW.

2. For power sales cases, imports would increase between 204 and 1,222 aMW. The increase in imports corresponds to a decrease in PSW obligation to generate to return to the PNW.

3. Mixed cumulative cases that combined two alternatives, one in power sales mode and the other in seasonal exchange mode, showed increased imports by the PSW from 207 to 698 aMW.

Table 4-8 Changes in Net Exports Over Intertie to PSW (- net export decreased, + net export increased)

Seasonal Exchange	Power Sales Cases	Mixed Cumulative

	Cases				Cases	
	From	To	From	To	From	To
aMW	-21	-169	+204	+1,222	+207	+698
Change vs. Base Case	<0.01%	6%	4%	29%	4%	19%

The results cited in Table 4-8 are based on a methodology which assumes that PNW imports displace California generation megawatt for megawatt. This may overstate the actual effects, which could range to lower displacement ratios. For an example, see the discussion of the BPA/SCE environmental exchange data in Section 4.4.3 below.

The effect of the proposed transactions on the dispatch of California resources depends on several factors, including seasonality, gas prices, and the resource mix available to the individual California customer. California resource displacement includes oil fuel during some conditions, less efficient gas-fired plants in the South Coast Air Basin and other high heat-rate oil or gas-fired plants. Under some load and supply conditions, it is possible that California resource generation may not be reduced, but power may be resold to other markets. Generation within the South Coast Air Basin would continue to be affected primarily by the availability of economy energy and would not be increased by return energy obligations.

CEC staff performed an initial assessment related to generic environmental exchanges that was addressed in ER-92. This analysis examined the narrow question of the ability of California utilities (Southern California Edison (SCE), Los Angeles Department of Water and Power (LADWP), Pacific

Gas & Electric (PG&E), and San Diego Gas & Electric (SDG&E)) to provide energy to the PNW for a worst-case level of 1,040 MW/month to aid deficits due to fish flows. It did not deal with the effect of summer deliveries to the PSW. The assumed time period for delivery to the PNW was January through April, while the alternatives studied here extend from October through March. The CEC analysis indicated that deliveries could be made without violating air quality compliance or transmission constraints and without adding to planned resource acquisitions. Analysis of the source of energy sent to the PNW by SCE, LADWP, PG&E, and SDG&E showed major reliance on gas generation,

including repowering projects and gas units subject to SCAQMD Rule 1135 NOx limits.
Figures 4-1 through 4-4 were taken from the January 1992 draft testimony by CEC staff on environmental exchanges for the ER-92 process. CEC staff noted that comments on the study indicated that gas use might have been somewhat overstated due to the analytical methodology and that ISW imports might have been understated.

4.4.2 PSW Resources Acquired and Deferred

The CEC ER-92 process already assumed a certain level of contribution from the PNW to the future electric power needs of California (see Chapter 2, Affected Environment). If the alternatives proposed were to make a greater contribution, the resource types that could be deferred by PNW contracts would tend to be in-State gas-fired CTs from new independent power producers or PURPA Qualifying Facilities, repowerings of existing gas-fired plants, and imports from other regions such as the ISW (mix of coal, gas, and nuclear) or Mexico (probably gas-fired). The market information on economic levels of new resource development is widely variable depending on source. Utility and independent power producer plans may vary greatly based on their financial policies and risk strategies. The California State regulatory environment makes it unreasonable to suppose that IOU in-State thermal resource additions would be justifiable based on PNW-PSW Intertie contracts. However, municipal and publicly owned utilities in California are not subject to the same regulation and may have an interest in adding resources for Intertie transactions.

CEC staff testimony for ER-92 referred to a study done assuming the California IOUs supplied return energy to the PNW to shape Columbia River spring flows for fish. Due to a projected IOU surplus of off-peak energy, the study concluded that there would be no resource acquisitions needed by IOUs to perform this exchange. This study did not address the likelihood of resource acquisition by municipals or other publicly owned California utilities. These entities may find it economic to acquire resources at least partly to enable them to participate in a seasonal exchange or other transaction using the Intertie with the PNW.

4.4.3 PSW Environmental Effects

This analysis emphasizes California air quality concerns as the key consequential environmental

externality. This is consistent with the focus of the CEC in its ER processes. While electric power resources have broader effects on land use, water use and quality, and other environmental components, the health effects of air emissions justify this focus. Much of California is currently violating national and State ambient air quality standards. Data on other effects of electric power generating stations on the environment is predominantly site-dependent and has limited information value when considering long-term transactions involving operation of undifferentiated integrated power systems.
If seasonal exchanges resulted in net generation changes of the magnitude seen in this eis analysis, annual California NOx emissions, assuming supply from generic gas-fired combustion turbines, could increase as much as 122 to 982 tons/year. This is small in context with California State NOx emissions of nearly 20,000 tons/year for 1992 and over 5,000 tons/year in the South Coast Air Basin alone. Also, the BPA Marketing and Joint Venture alternative would not necessarily lead to net annual increases in

California NOx emissions. Contract negotiations can produce arrangements which result in net decreases. Winter deliveries to the PNW can be served from more efficient PSW plants at lower heat rates. Parties with service areas in the South Coast Air Basin are able to displace less efficient, high heat rate operation of plants subject to SCAQMD Rule 1135 NOx limits. Support for this was contained in SCE's November 1992 Energy Cost Adjustment Clause filing before the CPUC regarding a 1991 environmental exchange with BPA. (Emissions data was not provided in ECAC filings by all California utilities that participated in environmental exchanges.) The exchange enabled SCE to avoid committing an equivalent MW amount of gas generation for over 65 percent of the summer delivery period. The return energy to BPA was delivered off-peak during fall or winter months, and approximately 58 percent was made with economy purchases from the PNW and other sources. The balance of the returns were made with off-peak gas generation. The exchange enabled SCE to reduce its total NOx emission by 71 tons, with no net increase in operating costs. Of the 71 tons saved, 39 tons were attributed to reduced summer on-peak gas generation. The remaining 32-ton reduction was achieved by shifting gas generation from summer on-peak to winter off-peak, making use of the most efficient advanced technology units at a low heat rate. This involved shifting from generating units with summer NOx rates of approximately 6.0 tons/aMW to units with rates of half that.

Assumed firm power sales would decrease PSW thermal resource generation by the amount of firm power delivered, decreasing daily maximum amounts and rates and annual total air emissions. If the increased net import amount seen in this study resulted in displacement of generic gas CTs, the NOx decreases could range between 1,185 and 7,100 tons/year.

Figure 4-1
Source of Energy Returned to the Pacific Northwest
Southern California Edison Company
Figure (Page4-22 Figure 4-1 Source of ...)

NWNF = Northwest Nonfirm
NWF = Northwest Firm
SWNF = Southwest Nonfirm
SWF = Southwest Firm

Figure 4-2
Source of Energy Returned to the Pacific Northwest
Los Angeles Department of Water & Power
Figure (Page-22 Figure 4-2 Source of ...)

NWNF = Northwest Nonfirm
NWF = Northwest Firm
SWNF = Southwest Nonfirm
SWF = Southwest Firm

Figure 4-3
Source of Energy Returned to the Pacific Northwest
San Diego Gas & Electric Company
Figure (Page4-24 Figure 4-3 Source of ...)

NWNF = Northwest Nonfirm
NWF = Northwest Firm
SWNF = Southwest Nonfirm
SWF = Southwest Firm

Figure 4-4
Source of Energy Returned to the Pacific Northwest
Pacific Gas & Electric Company
Figure (Page4-25 Figure 4-4 Source of ...)

NWNF = Northwest Nonfirm
NWF = Northwest Firm

SWNF = Southwest Nonfirm
SWF = Southwest Firm

CHAPTER 5 ENVIRONMENTAL CONSULTATION, REVIEW, AND PERMIT REQUIREMENTS 1

5.1 National Environmental Policy Act

This eis was prepared pursuant to regulations implementing the National Environmental Policy Act (42 USC 4321 et seq.), which requires Federal agencies to assess the impacts that their actions may have on the environment. Decisions will be based on understanding of the environmental consequences and actions will be taken to protect, restore, and enhance the environment.

5.2 Endangered and Threatened Species and Critical Habitat

The ESA of 1973, as amended, (16 USC 1536) requires Federal agencies to ensure that their actions do not jeopardize endangered or threatened species or their critical habitats. In compliance with Section 7, BPA requested from the U.S. Fish and Wildlife Service (USFWS) a list of endangered and threatened plant and animal species in the affected environment. This information was provided by the appropriate USFWS Field Offices in Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming, and is included in Appendix D.

Consultations regarding the effects of Federal hydropower operations on potential endangered or threatened Columbia River salmon species are done on the annual operating plans prepared by BPA, the COE, and the U.S. Bureau of Reclamation. BPA's actions to implement power-related activities such as the Intertie transmission access alternatives studied here will not conflict with the outcomes of such ESA consultations and no specific consultation is therefore planned on these alternatives.

5.3 Fish and Wildlife Conservation

The Fish and Wildlife Conservation Act of 1980 (16 USC 2901 et seq.) encourages Federal agencies to conserve and to promote conservation of nongame fish and wildlife species and their habitats. The Fish and Wildlife Coordination Act (16 USC 661 et seq.) requires Federal agencies undertaking projects affecting water resources to consult with the USFWS order to conserve or improve wildlife resources. The Pacific Northwest Electric Power Planning and Conservation Act (16 USC 839 et seq.) contains provisions intended to protect, mitigate, and enhance the fish and wildlife (including their spawning grounds and habitat) of the Columbia River and its tributaries. The Pacific Northwest Electric Power and Conservation Planning Council (Council) established under the Northwest Power Act developed a Regional Electric Power and Conservation Plan (Plan). In implementing its mandate to assure an adequate, efficient, economical, and reliable power supply, BPA must give due consideration to the protection, mitigation, and enhancement of the region's fish and wildlife resources. Major resources (resources with a planned capability greater than 50 average megawatts acquired for more than 5 years) acquired by BPA must be consistent with the Plan, including its fish and wildlife components, unless an exemption is granted by Act of Congress.

5.4 Heritage Conservation

A number of Federal laws and regulations have been promulgated to protect the nation's historical, cultural, and prehistoric resources. BPA must consider whether its actions may have an effect on a property listed or eligible for listing on the National Register of Historic Places, a property listed on the National Registry of Natural Landmarks, a property listed as a National Historic Landmark, a property listed on the World Heritage List, a property listed on a state-wide or local list, or the ceremonial rites or access to religious sites of Native Americans. The alternatives examined here are not expected to have such effects. In addition, BPA has executed a Programmatic Agreement with the Bureau of Reclamation; COE; U.S. Forest Service; the Advisory Council on Historic Preservation; the Idaho, Montana, and Washington State Historic Preservation Officers; the Colville Confederated Tribes; and the Spokane Tribe of Indians. This Programmatic Agreement effectively mitigates for impacts to cultural resources from changes in elevation at these reservoirs, satisfying BPA's responsibilities under Section 106 of the National Historic Preservation Act. The Programmatic Agreement also ensures BPA's consistency with the American Indian Religious Freedom Act and the Native American Graves Protection and Repatriation Act by providing for BPA participation in the disposition of Native American burials if such sites are discovered.

5.5 State, Area-wide, Local Plan and Program Consistency

In accordance with Executive Order 12372, this eis will be circulated to the appropriate state clearinghouses to satisfy review and consultation requirements.

5.6 Coastal Zone Management Consistency

The Coastal Zone Management Act of 1972 requires that Federal actions be consistent, to the maximum extent practicable, with approved state Coastal Zone Management Programs. The alternatives examined here are not expected to have coastal zone impacts.

5.7 Floodplains Management

Executive Order 11988 (Floodplain Management) and Department of Energy regulations implementing the Executive Order (10 CFR Part 1022) direct BPA to avoid, to the extent possible, the long- and short-term adverse impacts associated with the occupancy and modification of floodplains and to avoid direct and indirect support of floodplain development wherever there is a practicable alternative. The alternatives examined here are not expected to have such effects.

5.8 Wetlands Protection

Executive Order 11990 (Protection of Wetlands) and Department of Energy regulations implementing the Executive Order (10 CFR Part 1022) direct BPA to minimize the destruction, loss, or degradation of wetlands; and to preserve and enhance the natural and beneficial values of wetlands. The alternatives examined here are not expected to have such effects.

5.9 Farmland Protection

The Farmland Protection Policy Act (7 USC 4201 et seq.) requires Federal agencies to identify and take into account the adverse effects of their programs on the preservation of farmlands. The alternatives examined here are not expected to have such effects.

5.10 Recreation Resources

Each resource acquisition will be evaluated to determine if it affects a component of the National Wild and Scenic Rivers System or the National Trails System; a U.S. Forest Service or Wilderness Area or roadless area; a Bureau of Land Management Wilderness Area or Area of Critical Environmental Concern; a park or other area of ecological, scenic, recreational, or aesthetic importance; or converts property acquired or developed with assistance from the Land and Water Conservation Fund to other than outdoor public recreation uses. The alternatives examined here are not expected to have such effects. Effects due to operation of Federal Columbia River Resources will be dealt with under the System Operation Review decision process and eis.

5.11 Global Warming

A discussion of possible global warming effects has been included for all fossil fuel resource types analyzed in this eis. Greenhouse gases have been included in this analysis by volume of emissions only; dollar values have not been assigned.

5.12 Permits for Structures in Navigable Waters

If a proposed action includes a structure or work in, under, or over a navigable water of the United States; a structure or work affecting a navigable water of the United States; or the deposit of fill material or an excavation that in any manner alters or modifies the course, location, or capacity of any navigable water of the United States, a Section 10 Permit under the Rivers and Harbors Appropriations Act of 1899 will be required from the COE. The alternatives examined here are not expected to have such effects.

5.13 Permits for Discharges Into Waters of the United States

A Section 404 Permit (Permit for Discharges into the Waters of the United States) under the

Federal Water Pollution Control Act (Clean Water Act) of 1972 as amended will be required from the COE if an action includes the discharge of dredged or fill material into waters of the United States. The alternatives examined here are not expected to have such effects.

5.14 Permits for Rights-of-Way on Public Land

If an action involves the use of public or Indian lands not in accordance with the primary objective of the management of those lands, under the Federal Land Policy and Management Act (43 USC 1701 et seq.), a permit for a right-of-way across such lands will be required. The alternatives examined here are not expected to have such effects.

5.15 Energy Conservation at Federal Facilities

Energy conservation at Federal facilities need not be addressed since no alternative studied here includes the operation, maintenance, or retrofit of an existing Federal building; the construction or lease of a new Federal building; or the procurement of insulation products.

5.16 Pollution Control at Federal Facilities

In addition to their responsibilities under NEPA, Federal agencies are required to carry out the provisions of other Federal environmental laws. None of the alternatives discussed in this eis require any particular response with regard to these other Federal laws, which are more concerned with site-specific proposals and alternatives, rather than the broadly applied policy decisions being analyzed in this document.

To the extent applicable to a specific alternative presented in this eis, compliance with the standards contained in the following legislation is mandatory:

- Title 42 U.S.C. 7401, et seq., The Clean Air Act, as amended
- Title 33 U.S.C. 1251 et seq., The Clean Water Act, as amended
- Title 42, U.S.C. 300 F, et seq., The Safe Drinking Water Act, as amended
- Title 10 CFR Part 712, "Grand Junction Remedial Action Criteria"
- Title 40 CFR Part 190, "Environmental Radiation Protection Standards for Nuclear Power Operations"
- Title 40 CFR Part 191, "Environmental Radiation Protection Standards for Management and Disposal of Spent Nuclear Fuel, High-Level, and Transuranic Radioactive Wastes"
- Title 40 CFR Part 192, "Health and Environmental Protection Standards for Uranium and Thorium Mill Tailings"
- Title 42 U.S.C. 9601 [9615] et seq., The Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended

. Title 7 U.S.C. 136, et seq., The Federal Insecticide, Fungicide, and Rodenticide Act, as amended

. Title 42 U.S.C. 6901, et seq., The Resource Conservation and Recovery Act of 1976, as amended

. Title 15 U.S.C., et seq., The Toxic Substances Control Act, as amended; Title 40 CFR Part 761, "Polychlorinated Biphenyls (PCBs) Manufacturing, Processing, Distribution in Commerce, and Use Prohibitions"

. Title 42, U.S.C. 4901, et seq., The Noise Control Act of 1972, as amended

5.17 Other Standards

. Title 16 U.S.C. 1131, et seq., The Wilderness Act, as amended; Title 43 CFR Part 19, "Wilderness Preservation".

CHAPTER 6: LIST OF PREPARES

Name	eis Responsibility	Qualifications
Kathy Craig	PSW Market Analysis	BPA - 13 years; Resource Planning - 7 years, California Market Analysis - 6 years.
John Emery	Modeling and oversight, operational analysis	B.S., M.S., Economics; Pacific Northwest Laboratories - 2 years, Energy Policy Analyst. BPA - 5 years, Division of Rates; 3 years Resource Planning; 4 years Power System Analysis.
Maureen Flynn	Project Manager	B.S. Psychology; J.D., 1979, BPA - 13 years, Power Management and Environmental Review.

Cindy Horvath System	Modeling	M.P.H., Biostatistics; BPA - 10 years, Power Branch.
Sally Long 18 years; Transmission Section, 1 year	Transmission Policy Analysis	B.S., Sociology; BPA - 4 1/2 years Branch Intertie Intertie Section Chief.
Martha Pinkstaff Technical 4 years, Review/Rates.	Writer-Editor	B.A. Economics; Writing Certificate. BPA Economist - Rates, Writer-editor, 8 years, Coordination and
Randy Seiffert Engineering, Environmental	Thermal Resource Impacts	B.S., Chemical BPA - 16 years, Analysis.
Spencer Wedlund and 13 years, years.	Economic and Marketing Analysis	B.A., Economics, M.A., Economics. BPA Sales Revenue Forecasting - Contract Negotiator 2

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CHAPTER 7 LIST OF AGENCIES, ORGANIZATIONS AND PERSONS TO WHOM COPIES OF THE STATEMENT ARE SENT

FEDERAL AGENCIES

U.S. House of Representatives, Office of Honorable Conrad Burns, Kalispell, MT
U.S. House of Representatives, Office of Honorable Max Baucus, Kalispell, MT
U.S. Corps of Engineers, North Pacific Division, Portland, OR
U.S. Department of Agriculture, Pacific Southwest Region, San Francisco, CA

U.S. Department of Energy, Bonneville Power Administration, Sacramento, CA
U.S. Department of Energy, Bonneville Power Administration, Idaho Falls, ID
U.S. Department of Energy, Bonneville Power Administration, Portland, OR
U.S. Department of Energy, Federal Energy Regulatory Commission, Washington, DC
U.S. Department of Energy, Federal Energy Regulatory Commission, Pittsburgh, PA
U.S. Department of Energy, Western Area Power Administration, Sacramento, CA
U.S. Department of Energy, Western Area Power Administration, Billings, MT
U.S. Department of Energy, Western Area Power Administration, Golden CO
U.S. Department of Interior, Bureau of Indian Affairs, Portland, OR
U.S. Department of Interior, Bureau of Indian Affairs, Nespelem, WA
U.S. Department of Interior, Bureau of Indian Affairs, Toppenish, WA
U.S. Department of Interior, Bureau of Land Management, Billings, MT
U.S. Department of Interior, Bureau of Land Management, Portland, OR
U.S. Department of Interior, Bureau of Reclamation, Ephrata, WA
U.S. Department of Interior, Bureau of Reclamation, Sacramento, CA
U.S. Department of Interior, Fish & Wildlife Service, Portland, OR
U.S. Department of Interior, Fish & Wildlife Service, Vancouver, WA
U.S. Department of Interior, Fish & Wildlife Service, Cheyenne, WY
U.S. Department of Interior, Fish & Wildlife Service, Coulee Dam, WA

STATE OF ARIZONA
Governor's Office Executive Assistant, Phoenix, AZ

STATE OF CALIFORNIA
Energy Commission, Sacramento
Energy Commission, Northwest Project, Sacramento
California Energy Company Inc
California Oregon Transmission Project
Department of Fish & Game, Redding
Department of Water Resources, Sacramento
Energy Resource Conservation & Development, Sacramento
Public Utilities Commission, San Francisco
Office of Historic Preservation, Department of Parks & Recreation, Sacramento
Office of Permit Assistance, Governor's Office of Planning & Research, Sacramento

STATE OF CALIFORNIA
Local/Regional
City of Los Angeles, Department of Water & Power
City of Vernon

STATE OF IDAHO
Department of Health & Welfare, NEPA Contact, Boise
Historic Preservation Office, Boise
Senate Committee on Resources & Environment, Boise
Department of Planning & Policy, Boise

STATE OF MONTANA
Department of Fish Wildlife & Parks, Kalispell
Public Service Commission, Helena
Office of Budget & Program Planning, Helena
Office of Historic Preservation, Montana Historical Society, Helena
Local/Regional
County of Lincoln
County of Ravalli

STATE OF NEVADA
Division of Historic Preservation & Archeology, Carson City
Office of Community Services, Carson City
State of Nevada Clearinghouse

STATE OF NEW MEXICO
Department of Environment, Santa Fe
Division of Historic Preservation, Office of Cultural Affairs, Santa Fe

STATE OF OREGON
Department of Parks & Recreation, Salem
Public Utilities Commission, Salem
Economic Research Division, PUC, Salem
Local/Regional
City of Klamath Falls
County of Jackson, Department of Planning & Development

STATE OF UTAH
Department of Environmental Health, Salt Lake City
Department of Natural Resources, Salt Lake City
Public Service Commission, Salt Lake City
Utah Clearinghouse, Office of planning & Budget, Salt Lake City

STATE OF WASHINGTON
Clearing Up News
Office of Archaeology & Historic Preservation, Olympia
Office of Attorney General, Seattle
Office of Energy, Olympia
State of Washington, Utilities & Transportation Commission, Olympia
Department of Ecology, Section of Environmental Review, Olympia
Local/Regional
City of Seattle, Council
City of Seattle City Light Department, Energy Resources Planning Management

STATE OF WYOMING
Honorable Mike Sullivan, Governor, Cheyenne
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Public Service Commission, Cheyenne
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Coalition For Canyon Preservation, Protect Park Services, Hungry Horse, MT
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Direct Service Industries Inc, Portland, OR
Eco Northwest, Eugene, OR
Ecology & Environment Inc, Seattle, WA
Environmental Defense Fund, Oakland, CA
Flowind Corporation, San Rafael, CA
Friends of The Earth, Seattle, WA
G H Bowers Engineering, Seattle, WA
Georgia Pacific Corporation, Bellingham, WA
GES Consultants, Los Angeles, CA
Gray Panthers of Portland, Energy Study Commission, Portland, OR
Great Bear Foundation, Missoula, MT
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HDR Engineering Inc, Bellevue, WA

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Intermountain Gas Company, Boise, ID
JBS Energy Inc, Broderick, CA
John Nuveen & Company, Seattle, WA
League of Women Voters, Salem, OR
League of Women Voters, Pocatello, ID
National Wildlife Federation, Water Resources Program, Washington DC
Natural Resources Defense Council, Western Office, San Francisco, CA
Nevada League of Cities, Carson City, NV
Northwest Conservation Act Coalition, Seattle, WA
Oregon State Public Interest Research Group, Portland,OR
Oregon Wildlife Federation, Portland, OR
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California State University at Sacramento Library Documents Section
Eastern Montana College Library, Department of Documents
Evergreen State College, Daniel J. Evans Library
Fort Vancouver Regional Library
Oregon State University, Department of Kerr Library Documents, Corvallis, OR
Portland State University, Regional Depository Millar Library
Shasta County Library, Redding, CA
State of Washington, Office of Energy Library, Olympia, WA
Tacoma Public Library, Northwest Room, Tacoma, WA
United States Court of Appeals, 9th Circuit Library, Seattle, WA
University of Arizona Library, Government Documents Department Region Depository, Tucson, AZ
University of Montana Mansfield Library, Department of Regional Depository Documents, Missoula, MT
University of Nevada Library, Department of Government Public Regional Depository, Reno, NV
University of New Mexico, General Library Regional Depository, Albuquerque, NM
University of Oregon, Library Documents Section, Eugene, OR
University of Washington, Suzzallo Library Government Publications, Seattle, WA
Washington State University, Library Documents Section, Pullman, WA
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NORTHWEST POWER PLANNING COUNCIL
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Basin Electric Power Coop, Bismarck, ND
BC Hydro Power Authority, Resource Management, Vancouver, BC
BC Ministry of Energy Mines & Petroleum, Branch of Electricity Policy, Victoria, BC
Bechtel Civil & Minerals Inc, San Francisco, CA
Benton County PUD, Kennewick, WA
Benton Franklin Government Conference, Richland WA
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Emerald PUD, Springfield, OR
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General Electric Company, General Electric & Power Systems Sales, Tigard, OR
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Grays Harbor County PUD, Aberdeen, WA
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Pacific Gas & Electric, San Francisco, CA
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Salmon River Electric Coop, Challis, ID
San Diego Gas & Electric Company, Leucadia, CA

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Southern California Edison Company, Rosemead, CA
Springfield Utility Board, Springfield, OR
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Unity Light & Power Company, Burley, ID
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Spiegel & McDiarmid, Washington DC
Stoel Reeves Boley Jones & Grey, Portland, OR
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CHAPTER 8 GLOSSARY & ACRONYM LIST

Alternating current (AC): Electric current that reverses its direction of flow at regular intervals and has alternately positive and negative values; see Intertie.

Assured Delivery: Firm transmission service provided by BPA under terms of the Long-Term Intertie Access Policy under a transmission contract to wheel power between a scheduling utility and a PSW utility.

California-Oregon Transmission Project (COTP): A consortium of California utilities and other entities participating in the construction of the Third AC Intertie south of the Oregon-California border; also the 500-kilovolt transmission line proposed by the COTP.

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.

Demand Side Management: Strategies for reducing, redistributing, shifting, or shaping electrical loads, with an emphasis toward reducing or leveling load peaks. These strategies can be accomplished by influencing when and how customers use electricity. Examples include conservation measures, rate incentives for shifting peak loads, more effective controls, and energy storage schemes.

Direct current (DC): Electric current that may have pulsating characteristics but does not reverse direction at regular intervals, unlike alternating current; see Intertie.

Economy Energy: Generally, energy purchased on relatively short notice for periods of time to displace generation of plants using expensive fuels.

Endangered Species Act (ESA): An act passed by Congress in 1973 and subsequently amended, which provides for the conservation of endangered and threatened species of fish, wildlife, and plants and their ecosystems.

Energy: In this document, energy refers generally to megawatthours and is different from "capacity" and "power."

Energy Policy Act of 1992: An act passed by Congress in 1992 that provides, among other things, for FERC authority to order transmission access.

Environmental Impact Statement (eis): A document prepared to assist Federal agencies in complying with the National Environmental Policy Act; a discussion and analysis of potential significant environmental impacts of the proposed action and alternatives.

Federal Energy Regulatory Commission (FERC): A Federal agency that reviews BPA's rates, regulates transmission practices, and is responsible for enforcing provisions of the National Energy Policy Act.

Formula Allocation: The process by which Intertie capacity is made available for short-term sales of energy under the terms of BPA's Long-Term Intertie Access Policy.

Independent power producer (IPP): Non-utility producers or electricity who operate generation plants under the 1978 Public Utilities Regulatory Policy Act of 1978 (PURPA). Many independent power producers are cogenerators who produce power as well as steam or heat for their own use and sell the extra power to their local utilities.

Inland Southwest (ISW): The States of Nevada, Arizona, Colorado, Utah, and New Mexico.

Intertie: Relevant to this eis, the system of high-voltage transmission lines between the Pacific Northwest (Oregon) and the Southwest (California), currently two 500-kilovolt alternating current lines and one 1,000-kilovolt direct current line.

Intertie Development and Use (IDU) eis: BPA's eis completed in 1988 in aid of several BPA decisions regarding expansion of Intertie capacity, adoption of the Long-Term Intertie Access Policy, and design of long-term firm power contracts for marketing power over the Intertie.

Investor-owned utilities (IOUs): Providers of electric power and other services whose programs are financed by private (nongovernment) investors in the company's stocks and bonds.

Joint venture: Used here generally to refer to an agreement in which BPA and another PNW party provide portions of the delivery to a PSW party.

Long-Term Intertie Access Policy (LTIAP): BPA's policy, developed in 1988, for allocating use of the Federal portion of the Intertie for a period of at least 20 years.

Megawatt (MW): A measure of electrical power or generating capacity; one million watts.

Memorandum of Understanding (MOU): An agreement entered into by BPA and PNW parties interested in capacity ownership. The MOUs establish principles for the decision process on capacity ownership.

Million acre-feet (MAF): The measure of storage for fish flows; an acre-foot is the volume of water that will cover an area of one acre to a depth of one foot (326,000 gallons or 0.5 second foot days).

National Marine Fisheries Service: A Federal agency, under the Department of Commerce, responsible for managing fishery resources within the U.S. Fishery Conservation Zone (3-200 miles off the coast), including anadromous salmonids that return to spawn in the Columbia River Basin.

Non-attainment area: An area that has air pollution concentrations that do not comply with a portion of the National Ambient Air Quality Standards. See Chapter 2.

Non-Federal Participation (NFP): Participation in some form, ranging up to full facilities ownership, by non-Federal utilities/entities in BPA's share of the Third AC Intertie.

Non-scheduling utilities: BPA customer utilities that do not operate a generation control area or that do not schedule power deliveries with BPA.

Northwest Power Planning Council: An eight-member body, with two members each from Oregon, Washington, Idaho, and Montana, authorized by the Northwest Power Act of 1980 for the purpose of coordinated fish and wildlife and resource planning.

Pacific Northwest (PNW): The States of Washington, Oregon, and Idaho, plus portions of Montana, Nevada, Utah, and Wyoming.

Pacific Power & Light Company (PP&L): An investor-owned utility that shares ownership of the existing Intertie and related facilities and the Third AC line with BPA and Portland General Electric.

Pacific Southwest (PSW): Generally, the State of California.

Portland General Electric Company (PGE): An investor-owned utility that shares ownership of the existing Intertie and related facilities and the Third AC line with BPA and Pacific Power & Light.

Power: In this eis, refers generally to energy delivered during peak load hours at a specified capacity level.

Protected Areas: As developed by the Northwest Power Planning Council and enforced by the Long-Term Intertie Access Policy, areas protected from hydro project development due to the presence of wildlife, high-value resident fish, and anadromous fish, or areas that could support anadromous fish if investments were made in habitat, hatcheries, passage, or other projects.

Qualifying facility (QF): A renewable or cogeneration resource developed under the Public Utilities Regulatory Policy Act of 1978.

Resource Program: BPA's Resource Program develops a strategy and budget plan for development of conservation and other resources needed to meet BPA's loads.

System Operation Review (SOR): A process of analysis and public review being conducted by the Bonneville Power Administration, the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and cooperating agencies; the environmental analysis required to consider major changes in Columbia River system operations, including development of a mulitple-use operating strategy for the river system and renegotiation and renewal of the Pacific Northwest Coordination Agreement and other agreements related to the Columbia River Treaty between the United States and Canada.

Third AC: A construction project currently underway to expand the bidirectional capability of the Intertie transmission system; modifications to existing facilities and transmission additions in the Pacific Northwest will upgrade the portion of the AC Intertie north of the Oregon-California border to meet the planned increase for the southern portion (see COTP).

Transmission Agency of Northern California (TANC): A joint power agency consisting of 15 municipalities, public utility districts, and irrigation districts.

ACRONYMS

AC	Alternating Current
aMW	Average Megawatt
APCD	Air Pollution Control District
AQMD	Air Quality Management District
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
BGP	Burbank, Glendale, and Pasadena
BPA	Bonneville Power Administration
BRPU	Biennial Resource Plan Update
CCAA	California Clean Air Act
CEC	California Energy Commission
CO	Carbon monoxide
CO2	Carbon dioxide
COE	Corps of Engineers
COTP	California Oregon Transmission Project
COUNCIL	Northwest Power Planning Council
CPUC	California Public Utility Commission
DC	Direct Current
DSM	Demand-side Management
eis	Environmental Impact Statement
EPA	Environmental Protection Agency
ER	Electricity Report
ESA	Endangered Species Act
FERC	Federal Energy Regulatory Commission
Flow	Seis Flow Improvement Measures for Salmon Supplemental eis
gWh	Gigawatthours
IDU	eis Intertie Development and Use Environmental Impact Statement
IOU	Investor Owned Utility
ISW	Inland Southwest
kWh	Kilowatthour
LADWP	Los Angeles Department of Water and Power
LTIAP	Long-Term Intertie Access Policy
MAF	Million acre-feet
MOU	Memoranda of Understanding
MSR	Modesto-Santa Clara-Redding

MW	Megawatt
MWh	Megawatthours
NF	Nonfirm energy
NO2	Nitrogen dioxide
NOx	Nitrogen oxides
NFP	Non-Federal Participation
ODEQ	Oregon Department of Environmental Quality
OY	Operating Year
PGE	Portland General Electric
PNW	Pacific Northwest
PLAN	Electric Power Plan
PNGC	Pacific Northwest Generating Company
PROGRAM	Fish and Wildlife Program
PSW	Pacific Southwest
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
RFP	Request for Proposals
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SOR	System Operation Review
SO2	Sulfur dioxide
TSP	Total Suspended Particulates
UV	Ultraviolet

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CHAPTER 9: BIBLIOGRAPHY

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